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Vol. 3

Standard Technical Specifications
General Electric Plants, BWR/4

Bases (Sections 3.4–3.10)

Draft Report for Comment

Issued by the
U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

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PREFACE

This DRAFT NUREG presents the results of the Nuclear Regulatory Commission (NRC) staff review of the BWR Owners Group (BWROG) proposed new Standard Technical Specifications (STS) for the BWR/4 design. These new STS were developed based on the criteria in the interim Commission Policy Statement on Technical Specification Improvements for Nuclear Power Reactors, dated February 6, 1987.

The new STS will be used as bases for developing improved plant-specific technical specifications by individual nuclear power plant owners that have BWRs designed by General Electric. The NRC staff is issuing this draft new STS for a 30 working-day comment period. Following the comment period, the NRC staff will analyze comments received, finalize the new STS, and issue them for plant-specific implementation.

Comments should be submitted no later than March 15, 1991, in accordance with the following guidance: The exact wording of each proposed change should be marked in pen and ink on copies of all the affected pages of DRAFT NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4." Each proposed change should be numbered. Each proposed change should be accompanied with a separate technical justification, cross referenced to the applicable proposed change on the marked up pages.

Submit written comments to: David L. Meyer, Chief, Regulatory Publications Branch, Division of Freedom of Information and Publications Services, Office of Administration, U. S. Nuclear Regulatory Commission, Washington, DC 20555. Hand deliver comments to: 7920 Norfolk Avenue, Bethesda, Maryland, between 7:45 a.m. and 4:15 p.m. on Federal workdays.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The reactor coolant Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. It removes more heat from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The Recirculation System also controls reactivity over a wide span of reactors power by varying the recirculation flow rate to control the void content of the moderator. The reactor coolant Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable speed motor-driven recirculation pump, a flow control valve, and a motor-generator (MG) set to control pump speed and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

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BASES (continued)

BACKGROUND (continued)

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 55% to 100% rated power) without having to move control rods and disturb desirable flux patterns. Because of the negative reactivity addition when recirculation flow is decreased, reactor coolant pumps are tripped, resulting in a void buildup and rapid power reduction offsetting serious consequences that might occur in the unlikely event of an anticipated transient without scram.

Each recirculation loop is manually started from the control room. The MG set provides regulation of individual recirculation loop drive flows. The flow in each loop can be manually or automatically controlled.

APPLICABLE SAFETY ANALYSES

The operation of the reactor coolant Recirculation System is an initial condition assumed in the design basis loss-of-coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. If a LOCA occurs with a flow mismatch between the two loops, the analysis conservatively assumes the pipe break is in the loop with

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

the higher flow. The flow coastdown and core response are potentially more severe in this case, since the intact loop is starting at a lower flow rate and the core response is the same as if both loops were operating at the lower flow rate. The Recirculation System is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the FSAR.

A plant-specific LOCA analysis has been performed for the [Unit Name] assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) requirements are modified accordingly (Ref. 3).

The transient analyses of Chapter 15 of the [Unit Name] FSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MINIMUM CRITICAL POWER RATIO (MCPR) requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System (RPS) average power range monitor (APRM) instrument setpoints are also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR, MCPR, and APRM flow biased simulated thermal power setpoints for single loop operation are specified in the CORE OPERATING LIMITS REPORT.

The above analyses are for Design Basis Accidents (DBAs) and transients that establish the acceptance limits for recirculation loop operation. Reference to the analyses for these DBAs and transients is used to assess changes to recirculation loop operation as they relate to the acceptance limits.

Recirculation Loops Operating satisfies Criterion 2 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

Two recirculation loops are required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop, the assumptions of the LOCA analysis are satisfied. With the limits specified in SR 3.4.1.1 not met, the recirculation loop with the lower flow must be considered not in operation. With only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1), MCPR limits (LCO 3.2.2), and APRM flow biased simulated thermal power—high setpoint (LCO 3.3.1.1) may be applied to allow continued operation consistent with the assumptions of Reference 3.

APPLICABILITY

In MODES 1 and 2, requirements for operation of the reactor coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

With one recirculation loop not in operation, the non-operating loop must be returned to operation within 24 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits. The loop with the lower flow must be considered not in operation. Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to operating limits and RPS setpoints, operation with only one recirculation loop would satisfy the

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BASES (continued)

ACTIONS (continued)

requirements of the LCO and the initial conditions of the accident sequence.

The 24-hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in pumps. If zero or reverse flow is detected, the condition should be alleviated by changing pump speeds to reestablish forward flow or by tripping the pump.

B.1

With no recirculation loops in operation, or a single loop not restored to operating status within the required Completion Time and the single loop requirements of the LCO not applied, the reactor is required to be placed in a MODE in which the LCO does not apply. This is done by placing the plant in MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of design basis accidents and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Verification that the recirculation loop flows are within [10]% of rated core flow when operating at < [70]% of rated core flow and at ≤ [5]% core flow at ≥ [70]% of rated core flow every 24 hours when both loops are in operation will assure against loop flow mismatch. At low core flow (i.e., < 70% rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

[For this facility, jet pump flows are measured as follows:]

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered inoperable. The note in this SR specifies that the Surveillance is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The 24-hour Frequency is consistent with the Surveillance Frequency for jet pump operability verification and has been shown by operating experience to be adequate to detect off-normal jet pump loop flows in a timely manner.

REFERENCES

1. [Unit Name] FSAR, Section [6.3.3.4.], "[Title]."

2. [Unit Name] FSAR, Section [5.5.1.4.], "[Title]."

3. [Plant-specific analysis for single loop operation.]

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The reactor coolant Recirculation System is described in the Background section of the Bases for LCO 3.4.1, which discusses the operating characteristics of the system and how these characteristics affect the design basis accident analyses.

The jet pumps are part of the reactor coolant Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two-thirds core height, the vessel can be reflooded and coolant level maintained at two-thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains ten jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section in to the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis loss-of-coolant accident (LOCA) analysis evaluated in

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Reference 1. The analysis for the design basis LOCA establishes the acceptance limits for the jet pumps. Reference to this analysis is used to assess changes to the jet pumps as they relate to the acceptance limits.

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system including the beam holding a jet pump in place fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet Pumps satisfies Criterion 2 of the "RC Interim Policy Statement on Technical Specification Improvements.

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two-thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref 1). For a jet pump to be OPERABLE it must satisfy either criteria of SR 3.4.2.1.

APPLICABILITY

The jet pumps are required to be OPERABLE in MODES 1 and 2 since there is a large amount of energy in the reactor core and since the limiting Design Basis Accidents are assumed to occur in these modes. This is consistent with he requirements for operation of the Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Recirculation System is not required to be in operation, and when not in operation sufficient flow is not available to evaluate jet pump operability.

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BASES (continued)

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If the jet pumps cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in MODE 3 in which the LCO does not apply. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

The Completion Time of Required Action A.1 contains a Note to clarify that all jet pumps are treated as an entity with a single Completion Time, i.e., the Completion Time is on a Condition basis.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3).

Three criteria are provided. The first criterion (SR 3.4.2.1.a) is relatively sensitive to changes in jet pump performance and is relatively easy to perform. The second and third criteria (SR 3.4.2.1.b and SR 3.4.2.1c) provide a better indication of true jet pump OPERABILITY and therefore do not require as stringent limits, although they are more difficult to perform. If either criterion is

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

satisfied, the jet pumps are considered OPERABLE. Typically, the first criterion is verified; however, if this criterion is not met, the second or third must be met.

The first criterion examines the recirculation pump speed operating characteristics (pump and loop flow versus pump speed) that are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

Should this first criterion not be met, an additional criterion may be evaluated before declaring a jet pump inoperable. Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser-to-lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be seen as an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

[For this facility, jet pump flow is measured as follows:]

The 24-hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation, and is consistent with the Surveillance Frequency for recirculation loop operability verification.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	This SR is not required to be performed when THERMAL POWER is ≤ 25% of RATED THERMAL POWER. During low flow conditions, jet pump noise approached the threshold response of the associate flow instrumentation and precludes the collection of repeatable and meaningful data.
REFERENCES	1. [Unit Name] FSAR, Section [6.3], "[Title]." 2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1990. 3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset condition by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary.

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The S/RVs can actuate by either of two modes—the safety mode or the relief mode. In the safety mode (or spring mode of operation), the spring-loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. This satisfies the Code requirement. In the relief mode, valves may be opened manually or automatically at the selected preset pressure to perform the Automatic Depressurization System (ADS) function.

Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The S/RVs that provide the relief mode are the low-low set (LLS) valves and the ADS valves. The LLS requirements are specified in LCO 3.6.1.8 and the ADS requirements are specified in LCO 3.5.1. The instrumentation associated with the relief valve function is discussed in the Bases for LCO 3.3.6.3.

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam line isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, 11 S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event.

Reference 2 discusses additional events which are expected to actuate the S/RVs. From an overpressure standpoint, these events are bounded by the MSIV closure with flux scram event described above.

S/RVs satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Eleven S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). The system is OPERABLE when:

a. All components necessary to provide the function are functional and in service; and

b. All required surveillance is current and has demonstrated performance within acceptance criteria of each surveillance test.

The S/RV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the FSAR are based on these setpoints, but also include the additional uncertainties of ± 1% of the nominal setpoint drift and to provide an added degree of conservatism.

Operation with less valve OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

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BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, all S/RVs must be OPERABLE since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of remaining core heat.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling and reactor pressure is low enough that the overpressure limit can not be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1

With the safety function of one S/RV inoperable, the remaining OPERABLE S/RVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with two S/RVs inoperable. However, the reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE S/RVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for 14 days.

The 14-day Completion Time to restore the inoperable S/RVs to OPERABLE status is based on the relief capability of the remaining S/RVs, the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action. The Completion Time has been provided with a Note to clarify that all S/RVs are treated as an entity with a single Completion Time, i.e., the Completion Time is on a Condition Basis.

B.1 and B.2

With less than the minimum number of S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit

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BASES (continued)

ACTIONS (continued)

on reactor pressure. If the safety function of the inoperable S/RVs cannot be restored to OPERABLE status within the associated Completion Time or if the safety function of three or more S/RVs is inoperable, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in 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 MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This SR demonstrates that the S/RVs will open at the pressures assumed in the safety analysis of Reference 1. These pressure settings are as follows: [4 valves at 1090 ± 10.9, 4 valves at 1100 ± 11.0, and 3 valves at 1110 ± 11.1] psig. The demonstration of the S/RV lift settings must be performed during shutdown, since this is a bench test, and to be done in accordance with the provisions of SR 3.0.5. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

The 18-month Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.

SR 3.4.3.2

A manual actuation of each S/RV is performed to verify that, mechanically, the valve is functioning properly and that no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control valves or bypass valve, or by a change in the measured steam flow or 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 920 psig (the pressure recommended by the valve manufacturer). Plant startup is allowed prior to

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. If a valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the S/RV is considered OPERABLE. The 18-month Frequency is consistent with SR 3.4.3.1 to ensure that the S/RVs are manually actuated following removal for refurbishment and/or lift setting testing. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for test and provides a reasonable time to complete the SR.
REFERENCES	1. [Unit Name] FSAR, Section [5.2.2.2.4], "[Title]." 2. [Unit Name] FSAR, Section [15], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS operational LEAKAGE LCO is to limit LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and limits of LEAKAGE and the methods used to identify and quantify it.

10 CFR 50, Appendix A, GDC 30 (Ref. 1) requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting LEAKAGE detection systems for the RCPB.

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration of the leaks. Therefore, detection of LEAKAGE in the primary containment is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur which is detrimental to the safety of the facility or the public.

A limited amount of LEAKAGE inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. LEAKAGE from these systems should be detected and isolated from the primary containment atmosphere, if possible, to not mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss-of-coolant accident.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests that, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5-gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 3 and 4) shows that leak rates of hundreds of gpm will precede crack instability (Ref. 5).

The above analyses establish the acceptance limits for RCS operational LEAKAGE. Reference to these analyses is used to assess changes to the facility which could affect operational LEAKAGE as they relate to the acceptance limits.

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow-increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of the NRC Interim Policy Statement.

LCO

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause

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BASES (continued)

LCO (continued)

further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB.

b. Unidentified LEAKAGE

Five gallons per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring, drywell sump level monitoring, and containment air cooler condensate flow rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in a RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of 2 gpm in any 24-hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady-state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2-gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

LEAKAGE rate determination is made based on use of instrumentation meeting the OPERABILITY requirements of LCO 3.4.6, "RCS Leakage Detection Instrumentation."

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCOs apply, because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized. Therefore, detection of RCPB LEAKAGE is required during MODES 1, 2, and 3.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

A Note has been included to provide clarification that Conditions A, B, and C are treated as an entity with a single Completion Time.

ACTIONS

A.1 and B.1

With the unidentified LEAKAGE, the total LEAKAGE, or with both greater than the required limits, actions must be taken to identify the source and determine the significance of the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours are allowed to verify and reduce the LEAKAGE rates before the reactor must be shut down. If a change in unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

C.1 and C.2

An unidentified LEAKAGE increase of 2 gpm in a 24-hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated.

Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined to be not the source of the LEAKAGE within the required Completion Time. RCS type 304 and type 316 austenitic stainless-steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids must be evaluated and eliminated as the source of the increased LEAKAGE. This piping is very susceptible to IGSCC.

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BASES (continued)

ACTIONS (continued)

Alternatively, the LEAKAGE rate must be restored to within limits within the required Completion Time.

The 4-hour Completion Time is reasonable to properly verify the source or reduce the LEAKAGE increase before the reactor must be shut down without unduly jeopardizing plant safety.

D.1 and D.2

If any one of the Required Actions A.1 and B.1 and C.1 and C.2 cannot be met within the 4-hour Completion Time, the reactor must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in 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 MODES from full power in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. LEAKAGE detection instrumentation is discussed in more detail in the Bases for LCO 3.4.6. Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, any method may be used to quantify LEAKAGE within the guidelines of Reference 2. In conjunction with alarms and other administrative controls, an 8-hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking trends.

SR 3.4.4.2

The leaktight integrity of the RCPB is verified by visual inspection. The Inservice Testing Program and operational hydrostatic tests at normal operating pressure are acceptable means of verifying no RCPB LEAKAGE. The 18-month Frequency is based on the refueling cycle for inspection accessibility and adequately verifies RCPB integrity.

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BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 30, "Quality Of Reactor Coolant Pressure Boundary."

2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3. GEAP-5620, "Failure Behavior in ASTM A106 Pipes Containing Axial Through-Wall Flaws," April 1968.

4. NUREG-76/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.

5. [Unit Name] FSAR, Section [5.2.7.5.2], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3) define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB) that separate the high pressure RCS from an attached low pressure system. PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.4.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss-of-coolant accident (LOCA) outside of containment, an unanalyzed accident, which could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 Reactor Safety Study (Ref. 5) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 6) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This later study concluded that periodic leak testing of the PIVs can substantially reduce intersystem LOCA probability.

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BASES (continued)

BACKGROUND (continued)

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System;

c. High Pressure Coolant Injection System; and

d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 7.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission-product barrier.

APPLICABLE SAFETY ANALYSES (continued)

Reference 5 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is [the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCS pressure boundary, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is typically designed for [800] psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.]

Reference 6 evaluated various PIV configurations, leak testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leak testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

Leakage from the PIVs is a factor in the dose rates that are used in safety and accident analyses. Therefore, the leakage must be maintained within LCO limits to ensure that assumptions used in the analyses are valid.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

PIV leakage is not considered in any Design Basis Accident analyses, however. This specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment, which has not been analyzed. Compliance with this LCO ensures that an unanalyzed condition will not be entered. Therefore, RCS PIV leakage satisfies Criterion 2 of the NRC Interim Policy Statement.

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission-product barrier.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leak tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leak rate limit based on valve size was superior to a single allowable value.

Reference 8 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate is adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

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BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

A Note has been added to provide clarification that each flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

ACTIONS

A.1, A.2.1, and A.2.2

Four hours are provided to reduce leakage in excess of the allowable limit. The period permits operation to continue under stable conditions while corrective actions to reseat the leaking PIVs are taken. The 4 hours allow these actions and restrict the time of operation with leaking valves.

Alternatively, the flow path must be isolated by two other valves. Required Action A.2.1 and Required Action A.2.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB.

Required Action A.2.1 requires that the initial isolation with one valve must be performed within 4 hours of exceeding the limit. This 4-hour Completion Time is based on the same rationale as the time for Required Action A.1.

Required Action A.2.2 specifies that the double isolation barrier of two valves be restored by closing another valve qualified for isolation or restoring one leaking PIV. The 72-hour time after exceeding the limit considers the time required to complete the action and the low probability of a second valve failing during this time period.

RCS PIV leakage is considered out of limits if the equipment used to measure RCS PIV leakage is determined to be inoperable at the time SR 3.4.6.1 is performed. Required

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BASES (continued)

ACTIONS (continued)

Action A.1 or Required Action A.2.1 and Required Action A.2.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If leakage cannot be reduced or the system isolated, the RCS must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in MODE 3 within 12 hours and MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.2.1 or Required Action A.2.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

[For this facility, RCS PIV or isolation valve leakage is measured as follows:]

Testing is to be performed every 9 months, but may be extended up to a maximum of 18 months, a typical refueling cycle, if the plant does not go into MODE 4 for at least 7 days. The 18-month Frequency required in 10 CFR 50.55a(g) (Ref. 9), is within the American Society of Mechanical Engineers (ASME) Code, Section XI Frequency requirement (Ref. 10) and is based on the prudence of performing Surveillances such as this only during an outage. The Surveillance needs stable conditions and has the potential for an unplanned plant transient if performed with the plant at power.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

SR 3.0.4 is excepted for entry into MODE 3 to permit leak testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Section 50.2, "Definitions—Reactor Coolant Pressure Boundary."

2. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, "Codes and Standards," Subsection (c), "Reactor Coolant Pressure Boundary."

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section V, "Reactor Containment," Part 55, "Reactor Coolant Pressure Boundary Penetrating Containment."

4. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants."

5. U.S. Nuclear Regulatory Commission (NRC), "Reactor Safety Study—An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," Appendix V, WASH-1400 (NUREG-75/014), October 1975.

6. U.S. NRC, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," NUREG-0677, May 1980.

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BASES (continued)

REFERENCES (continued)

8. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," paragraph IWV-3423(e).

9. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, "Codes and Standards," Subsection (g), "Inservice Inspection Requirements."

10. ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, "Inservice Testing of Valves in Nuclear Power Plants," paragraph IWV-3422.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS LEAKAGE Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting LEAKAGE detecting systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). LEAKAGE detection systems for the RCS are provided to alert the operators when LEAKAGE rates above normal background levels are detected and also to supply quantitative measurement of LEAKAGE rates. The Bases for LCO 3.4.5 discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of two or three independently monitored variables, such as sump level changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump has transmitters that supply level indications in the main control room.

The floor drain sump level indicators have switches that start and stop the sump pumps when required. A timer starts each time the sump is pumped down to the low level setpoint.

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BASES (continued)

BACKGROUND (continued)

If the sump fills to the high level setpoint before the timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit.

A flow indicator in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room. The pumps can also be started from the control room.

The drywell air monitoring systems continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell air particulate and gaseous radioactivity monitoring systems are not capable of quantifying LEAKAGE rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour. Larger changes in LEAKAGE rates are detected in proportionally shorter times (Ref. 3).

[Condensate from four of the six drywell coolers is routed to the drywell floor drain sump and is monitored by a flow transmitter which provides indication and alarms in the control room. This Drywell Air Cooler Condensate Flow Rate Monitoring System serves as an added indicator, but not quantifier, of RCS unidentified LEAKAGE.]

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 4 and 5). Each of the LEAKAGE detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room.

A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Modification to the RCS LEAKAGE detection instrumentation could affect the ability to detect LEAKAGE. Therefore, Reference 6 should be referred to when making changes to the RCS LEAKAGE detection instrumentation to assess the effect of the changes in relation to the acceptance limits.

RCS LEAKAGE detection instrumentation satisfies Criterion 1 of the NRC Interim Policy Statement.

LCO

The drywell floor drain sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE. The other monitoring systems provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the LEAKAGE detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

[For this facility, OPERABLE LEAKAGE detection instrumentation consists of the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure LEAKAGE detection instrumentation OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the LEAKAGE detection instrumentation inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, LEAKAGE detection systems are required OPERABLE to support LCO 3.4.5, "RCS Operational LEAKAGE." This applicability is consistent with that for LCO 3.4.5.

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BASES (continued)

ACTIONS

A.1, A.2.1 and A.2.2

With the drywell floor drain sump monitoring system inoperable, no other form of sampling can provide the equivalent information. However, the atmospheric activity monitor [and the drywell air cooler condensate flow rate monitor] does provide indication of changes in LEAKAGE. Twenty-four hours are allowed to restore the drain sump monitoring system to OPERABLE status, or Condition E must be entered. Twenty-four hours limits the time that operation can continue without the ability to measure the leakage rate and establish compliance with the LEAKAGE limits. Alternatively, leakage rate may be determined by manually pumping the sump or by measuring the sump level differences every 4 hours. If neither of these two methods are available, Condition E must be entered since LEAKAGE cannot be quantified.

With the drywell floor drain sump monitoring system inoperable, but with leakage rate being measured by manually pumping the sump or measuring sump level differences, operation may continue for 30 days. The 30 days allow sufficient time to repair the system and recognize that a method to quantify leakage rate is available, but prevent operation of the plant for a long period with a degraded LEAKAGE detection system.

B.1 and B.2

With the required primary containment atmospheric particulate and gaseous monitoring system inoperable, grab samples of the containment atmosphere shall be taken and analyzed to provide periodic information. Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation for up to 30 days.

The 12-hour interval provides periodic information that is adequate to detect LEAKAGE. The 30-day Completion Time for restoration recognizes that at least one other form of leak detection is available.

[C.1]

[With the required primary containment air cooler condensate flow rate monitoring system inoperable, samples shall be

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BASES (continued)

ACTIONS (continued)

taken and analyzed every 12 hours to provide periodic information. The 12-hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leak detection are available.]

[D.1 and D.2]

[With the containment atmosphere radioactivity monitor and the containment air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the containment sump monitor. This condition does not provide the required diverse means of LEAKAGE detection. The Required Action is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended LEAKAGE detection diversity. The 30-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.]

E.1 and E.2

If a Required Action of Condition A, B, C, or D cannot be met within the required Completion Time, the reactor must be placed in a MODE in which the LCO does not apply. This requires placing the reactor 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 perform the actions in an orderly manner and without challenging plant systems.

F.1

With all required monitors inoperable, no automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1, SR 3.4.6.2, and SR 3.4.6.3

These SRs are the performance of a CHANNEL CHECK of each of the RCS LEAKAGE detection monitors. The check gives reasonable confidence that each channel is operating properly. The Frequency of 12 hours is based on

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

instrument reliability and is reasonable for detecting off-normal conditions. For this facility, a CHANNEL CHECK consists of [ ].

SR 3.4.6.4, SR 3.4.6.5, and SR 3.4.6.6

These SRs are the performance of a CHANNEL FUNCTIONAL TEST on each of the RCS LEAKAGE detection monitors. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation. For this facility, a CHANNEL FUNCTIONAL TEST consists of [ ].

SR 3.4.6.7, SR 3.4.6.8, and SR 3.4.6.9

These SRs are the performance of a CHANNEL CALIBRATION for each of the RCS LEAKAGE detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of [18] months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven this Frequency is acceptable. For this facility, a CHANNEL CALIBRATION consists of [ ].

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50 (10 CFR 50), "Domestic Licensing of Production and Utilization Facilities," Appendix A, Section IV, "Fluid Systems," General Design Criterion 30, "Quality of Reactor Coolant Pressure Boundary."

2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary LEAKAGE Detection Systems," May 1973.

3. [Unit Name] FSAR, Section [5.2.7.2.1], "[Title]."

4. GEAP-5620, "Failure Behavior in ASTM A106 Pipes Containing Axial Through-Wall Flows," April 1968.

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BASES (continued)

REFERENCES (continued)

5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.

6. [Unit Name] FSAR, Section [5.2.7.5.2], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

This LCO contains both iodine and total specific activity limits. The iodine isotopic activities are expressed in terms of a DOSE EQUIVALENT I-131 per gram of reactor coolant. Total specific reactor coolant activity is limited on the basis of the weighted average beta and gamma energy levels in the coolant. The allowable levels are intended to limit the 2-hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the FSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam line isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2-hour thyroid and whole

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

body doses at the site boundary, resulting from an MSLB outside containment during steady-state operation, will not exceed 10% of the dose guidelines of 10 CFR 100. This is the acceptance limit for the MSLB analysis.

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of the NRC Interim Policy Statement.

LCO

The specific iodine activity is limited to 0.2 μCi/gm DOSE EQUIVALENT I-131, and the total specific activity is limited to $100/\bar{E}$ μCi/gm. These limits ensure the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the MSIVs closed, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

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BASES (continued)

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is less than or equal to 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 48-hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

DOSE EQUIVALENT I-131 specific activity is considered out of limits if the equipment used to measure DOSE EQUIVALENT I-131 specific activity is determined to be inoperable at the time SR 3.4.7.2 is performed. Required Actions A.1 and A.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If the DOSE EQUIVALENT I-131 cannot be restored to less than or equal 0.2 μCi/gm within 48 hours, or if at any time it is greater that 4.0 μCi/gm, it must be determined at least every 4 hours and the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12-hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems.

C.1

When the reactor coolant specific activity is greater than $100/\bar{E}$ μCi/gm, the reactor must be placed in MODE 3 with all main steam lines isolated within 12 hours. The required

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BASES (continued)

ACTIONS (continued)

MODE 3 operation ensures the reactor is subcritical. Closing the MSIVs eliminates the potential radioactivity release path to the environment during the MSLB event.

The 12-hour Completion Time is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner, and to isclate the main steam lines, without challenging plant systems.

Gross specific activity is considered out of limits if the equipment used to measure gross specific activity is determined to be inoperable at the time SR 3.4.7.1 is performed. Required Action C.1 applies to restoring such equipment to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

The Surveillance requires performing a gamma-isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once per 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with RCS average temperature at least 500°F. The 7-day Frequency considers the unlikelihood of a gross fuel failure during this short time frame.

SR 3.4.7.2

This Surveillance is performed, in MODE 1 only, to ensure iodine remains within limit during normal operation, and following fast power changes when fuel failure is more apt to occur. The 14-day Frequency is adequate to trend changes in the iodine activity level considering gross activity is monitored every 7 days. The Frequency, between 2 and

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

6 hours after a power change of greater than or equal to 15% RATED THERMAL POWER within a 1-hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

[For this facility, DOSE EQUIVALENT I-131 specific activity is measured as follows:]

SR 3.4.7.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. Operating experience has shown that $\bar{E}$ does not change rapidly and the Frequency of 184 days recognizes this.

Note 1 states that SR 3.0.4 does not apply so sampling can be performed in MODE 1. Note 2 requires that the sample be taken after 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance," 1973

2. [Unit Name] FSAR, Section [15.1.40], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR)—Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce and maintain the temperature of the reactor coolant to ≤ 200°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the conditions for cold shutdown operation.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of two motor-driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.1).

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Those LCOs that operating experience and probabilistic risk assessment have generally shown to be important to public health and safety are retained as Technical Specifications.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and

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BASES (continued)

LCO (continued)

valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. In MODE 4, the RHR cross-tie valve (2E11-F010) may be opened to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem. Additionally, each 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. In MODES 3 and 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required.

An RHR pump is OPERABLE when it is capable of being powered and able to provide flow if required.

[For this facility, the following support systems are required to be OPERABLE to ensure RHR shutdown cooling subsystem OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RHR shutdown cooling subsystems inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure above the RHR cut-in permissive pressure, this LCO is not applicable. Under these conditions, the permissive does not allow placing the low pressure RHR shutdown cooling subsystem into operation. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures above the RHR cut-in permissive pressure is typically accomplished by boiling in the core and condensing the steam in the main condenser.

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BASES (continued)

APPLICABILITY (continued)

In MODE 3 with reactor steam dome pressure below the RHR cut-in permissive pressure ([ ] psig), and in MODE 4, the RHR System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature below 200°F.

The requirements for decay heat removal in MODE 5 are discussed in LCO 3.9.8 and LCO 3.9.9.

The Note permits both RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8-hour period, provided that one subsystem is OPERABLE and the coolant temperature remains below 200°F. The margin to boiling should be low enough that the time anticipated for being without forced RCS flow will be less than 2 hours and not long enough for the coolant temperature to reach 200°F. When this temperature is approached, the OPERABLE RHR subsystem will be placed in service. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption without violating the LCO.

ACTIONS

A.1, A.2.1, A.2.2, and A.2.3

With one RHR shutdown cooling subsystem inoperable for decay heat removal, the inoperable subsystem must be restored to OPERABLE status within 8 hours. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability.

An alternative to Required Action A.1 is to establish an alternate method of decay heat removal within 8 hours. This alternate method need not be safety grade; however, if it is not, a safety-grade method must be demonstrated to be OPERABLE, by test or analysis, within 24 hours.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay

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BASES (continued)

ACTIONS (continued)

heat removal by ambient losses can be considered as contributing to the alternate method capability.

[One alternate safety-grade shutdown cooling function is provided by pumping water from the suppression pool through the RHR heat exchanger and discharging water into the reactor via the low pressure coolant injection (LPCI) discharge flow path. A cooling loop is established with the reactor pressure vessel by returning vessel water to the suppression pool via the main steam line safety relief valves and their discharge piping. This method uses safety-grade and seismically qualified equipment. This method can withstand a loss of offsite power event. Alternate methods that can be used are the Spent Fuel Pool Cooling System and the Reactor Water Cleanup System.]

The 8-hour Completion Time to either restore the RHR shutdown cooling subsystem or establish an alternate method of decay heat removal is based on the importance of the RHR shutdown cooling function, the level of redundancy provided, and a reasonable time for completing the Required Action.

The 24-hour Completion Time to demonstrate that an alternate safety-grade decay heat removal method is OPERABLE provides sufficient time to perform tests or analyses while limiting operation with the loss of safety-grade redundancy for the decay heat removal function.

Since the alternate method of removing decay heat may not be as reliable, overall, as the RHR shutdown cooling subsystem, the inoperable RHR shutdown cooling subsystem is required to be returned to OPERABLE status within 14 days. The 14-day Completion Time is based on the importance of the shutdown cooling function and limits the period of operation with an alternate method of cooling, yet allows time for repair of the RHR shutdown cooling subsystem.

B.1, B.2.1, B.2.2, and B.2.3

If one inoperable RHR shutdown cooling subsystem cannot be restored to OPERABLE status within the associated Completion Time, or if both subsystems are inoperable, action must be taken immediately to restore one RHR shutdown cooling subsystem to OPERABLE status or to establish an alternate method of decay heat removal for each inoperable subsystem.

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BASES (continued)

ACTIONS (continued)

The alternate method need not be safety grade; however, if it is not, for each inoperable subsystem a safety-grade method must be demonstrated to be OPERABLE, by test or analysis, within 24 hours. (See the discussion under Required Action A.1, Required Action A.2.1, Required Action A.2.2, and Required Action A.2.3 regarding alternate methods.)

In addition to the alternate method process, one RHR shutdown cooling subsystem must be restored to OPERABLE status within 72 hours.

Immediate action ensures that decay heat removal is available at all times and signifies the importance of beginning restoration without delay and continuing until a method of decay heat removal is established. The basis for the 24-hour Completion Time is the same as for Required Action A.2.2. The 72-hour Completion Time for restoring one subsystem to OPERABLE status considers the importance of having at least one subsystem OPERABLE and the restoration time.

C.1, C.2, C.3, and C.4

With no RHR shutdown cooling subsystem in operation, except as permitted by the Applicability Note, forced reactor coolant circulation must be restored or an alternate method must be established within 2 hours. The alternate method need not be safety grade; however, if it is not, a safety-grade method must be demonstrated to be OPERABLE, by test or analysis, within 24 hours. (See the discussion under Required Action A.1, Required Action A.2.1, Required Action A.2.2, and Required Action A.2.3 regarding alternate methods.)

The 2-hour Completion Time considers the time necessary to re-establish forced circulation and prevent boiling away coolant that could lead to fuel failure and spread contamination and require significant makeup to the RCS. The basis for the 24-hour Completion Time to demonstrate an OPERABLE safety-grade cooling method is the same as for Required Action A.2.2. In addition to establishing forced circulation, reactor coolant temperature and pressure must be monitored once per hour to provide adequate warning of potential problems without forced circulation.

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BASES (continued)

ACTIONS (continued)

An RHR shutdown cooling subsystem must be restored to operation within 72 hours. The 72-hour Completion Time represents a reasonable time for restoration of a subsystem to operation without relying on an alternate method of decay heat removal for an extended period of time.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

The 31-day Frequency of this SR is based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. This SR does not require any testing or valve manipulation; rather, it involves verification by means of system walkdown that those valves outside containment and not locked, sealed, or otherwise secured in position can be aligned to their correct position. Since these valves are readily accessible to personnel during normal plant operation and verification of their position is relatively easy, the 31-day Frequency was chosen to provide additional assurance that the valves are in the proper position. Because some of the required valves are interlocked closed when above the RHR cut-in permissive pressure, an allowance is provided to test the valves once, 12 hours after pressure has been reduced below the cut-in permissive pressure. This allows conditions to be established under which the test may be performed.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system P/T changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the P/T changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

LCO 3.4.9 contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic testing (ISLH), and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides limits for both heatup and criticality.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when loop P/T indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1) requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

Reference 1 addresses the concern that undetected flaws can exist in the RCPB components and can result in brittle (non-ductile) failure if subjected to unusual pressure or thermal stresses. Certain RCS P/T combinations can cause stress concentrations at flaw locations, which, in

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BASES (continued)

BACKGROUND (continued)

turn, can cause flaw growth and result in failure before the ultimate strength of the material is reached. Material toughness resists and can even arrest flaw growth.

Material toughness varies with temperature and is lower at room temperature than at operating temperature. Toughness also depends on the chemistry and impurities of the base material, weld material, and heat-affected zone material. Furthermore, neutron fluence affects material toughness by decreasing ductility; the effect accumulates, and the portion of the RCPB in a high fluence area, the vessel beltline region, steadily decreases in ductility with exposure time.

Linear elastic fracture mechanics (LEFM) methodology is used to determine the stresses and material toughness at locations within the RCPB. The LEFM methodology follows the guidance given by 10 CFR 50, Appendix G; ASME Section III, Appendix G; and Regulatory Guide 1.99 (Ref. 3). Although any place in the RCPB is subject to non-ductile failure, the more restrictive limits apply to the vessel beltline, the vessel closure head, and the vessel outlet nozzles. With increased neutron fluence, the vessel beltline, with base metals and welds, typically becomes the most restrictive region.

Material toughness properties of the ferritic materials of the reactor vessel are determined in accordance with the NRC Standard Review Plan (Ref. 4), American Society for Testing Materials (ASTM) E 185 (Ref. 5), and additional reactor vessel requirements. These properties are then evaluated in accordance with Reference 2.

One indicator of the temperature effect on ductility is the nil-ductility temperature (NDT). The NDT is that temperature below which non-ductile fracture failure may occur. Ductile failure may occur above the NDT.

A range of NDT data points for the steel alloy used in reactor vessel fabrication has been established by testing, but the exact value of NDT cannot be determined. Therefore, a nil-ductility reference temperature (RT_{NDT}) has been established by experimental means. The neutron

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BASES (continued)

BACKGROUND (continued)

embrittlement effect on the material toughness is reflected by increasing the RT_{NDT} as exposure to neutron fluence increases.

In effect, the temperature below which non-ductile failure can occur increases over time in operation. Reference 3 provides guidance for evaluating the effect of neutron fluence. To assist in evaluating the amount of RT_{NDT} shift to be applied, surveillance specimens, made up of samples of reactor vessel material, are placed near the inside wall of the reactor vessel in the beltline region.

As the RT_{NDT} increases with vessel exposure to neutron fluence and the material toughness decreases, the P/T limit curves are correspondingly adjusted. This gives limits that provide pressure boundary protection over the design life of the vessel. The effect of the RT_{NDT} shift is to cause the pressure limit to decrease at a given temperature.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 5) and Appendix H of 10 CFR 50 (Ref. 6). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 3.

This specification provides two types of limits:

a. Reactor coolant P/T curves that define allowable operating regions; and

b. Limits on the allowable rate of change of temperature of the reactor coolant, which affect the thermal gradients through the wall of the vessel and, thus, the tensile stresses in the wall.

In use, the P/T curves are primarily for prevention of non-ductile failure, whereas the limits on rate of change assist in preventing both ductile and non-ductile failures.

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most

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BASES (continued)

BACKGROUND (continued)

restrictive. At any specific pressure temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The calculation used to generate ISLH testing curve uses different safety factors (per Ref. 2) than the heatup and cooldown curves. The ISLH testing curve also extends to the RCS design pressure of 2500 psia.

The criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the ISLH testing.

The P/T limit curves and associated temperature rate-of-change limits are developed in conjunction with stress analyses for large numbers of operating cycles and provide conservative margins to non-ductile failure. Although created to provide limits for these specific normal operations, the curves also can be used to determine if an evaluation is necessary for an abnormal transient.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that could have resulted in brittle failure of the RCPB, possibly leading to a non-isolable leak or loss-of-coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. ASME Code, Section XI, Appendix E (Ref. 7) provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation avoid encountering pressure, temperature, and temperature rate-of-change conditions that might cause undetected flaws to propagate and cause non-ductile failure of the RCPB, a condition which is unanalyzed. Reference 8 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

The analyses comprise a number of steps that establish the limits. Following are the basic elements:

a. Define the temperature profile. The reactor coolant temperature rate of change is defined so that normal plant operation can readily proceed without constraint. Cooldown and ISLH testing rates of change are similarly defined. These rates of change become LCO limits, as well as the bases for the heat transfer calculations.

b. Perform heat transfer calculations. The results determine the thermal gradient through the vessel wall. The analyses account for variances in flow rate and the consequent changes in the rate of heat transfer between the reactor coolant and the wall during different stages of heatup and cooldown.

c. Establish the material toughness as a function of RT_{NDT}. ASME Section III, Appendix G provides the basis for RT_{NDT} and Regulatory Guide 1.99 provides the basis for adjusting RT_{NDT} as a function of neutron fluence and material constituents and impurities.

d. Perform a LEFM analysis to establish the P/T limits. The criterion for setting the limits is that the combined P/T stresses cannot exceed the material toughness for the specific temperature under examination. The analytical stress concentration at each location is driven by postulating specific flaw sizes. Stress intensity factors for P/T are

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

calculated and compared to a reference pressure stress intensity factor. Safety factors are applied to the pressure stress intensity factor.

With the material toughness established as a function of RT_{NDT}, stress analyses are performed per Reference 2 to set the P/T limits. The limiting location of maximum stress may vary during heatup or cooldown operations, depending on pressure, temperature, and temperature rates of change.

Thus, the heatup and cooldown curves are composites of the limiting pressures at specific temperatures, with separate curves derived for varying heatup and cooldown rates.

e. <u>Adjust the curves</u>. The curves are adjusted for differences in elevation between the instrument tap locations and the vessel beltline and for system pressure losses at different stages of heatup or cooldown. The limit curves are also adjusted for the estimated instrument errors of the wide-range P/T instruments.

The P/T limit curves must account for a requirement from Reference 1 that the minimum temperatures of the closure head flange and vessel flange regions must be at least 120°F above the limiting RT_{NDT} for these regions when the pressure exceeds 20% of the preservice hydrostatic test pressure.

The calculation assumes a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, 1/4 T, and a length of 3/2 T exists first at the inside of the vessel wall, then at the outside of the vessel wall. These dimensions are well within the current detection capabilities of inservice inspection techniques. Therefore, the P/T limit curves developed for this postulated defect are conservative and provide adequate protection against non-ductile failure.

To ensure that the radiation embrittlement effects on the RT_{NDT} are accounted for in the calculations for the limit curves, the most limiting RT_{NDT} (of the various

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

reactor vessel components) is used and includes a radiation-induced shift corresponding to the end of the fluence period for which heatup and cooldown curves are generated. This shift is a function of both the neutron fluence and the copper and nickel contents of the vessel material. The heatup and cooldown P/T limit curves include predicted adjustments for the RT_{NDT} shift and state the number of effective full power years for which this shift applies.

The actual shift in RT_{NDT} of the beltline region material will be established periodically during operational history by removing and evaluating the irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and at the vessel inside wall are essentially identical, the measured transition shift for a sample can be applied to the adjacent section of the reactor vessel. The limit curves must be recalculated when the actual RT_{NDT} from the surveillance specimens is higher than the calculated RT_{NDT} for the presumed radiation exposure.

RCS P/T limits satisfies Criterion 2 of the NRC Interim Policy Statement.

LCO

The elements of this LCO are:

a. RCS pressure, temperature, and heatup or cooldown rate are within the limits specified in LCO 3.4.9.

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within the limit of the PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) during recirculation pump startup.

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel meets the limit of the PTLR during pump startup.

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BASES (continued)

LCO (continued)

d. RCS P/T are within the criticality limits specified in the PTLR.

e. The reactor vessel flange and the head flange temperatures are within the limits of the PTLR when reactor vessel head bolting studs are tensioned.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to non-ductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of non-ductile (brittle) failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3 and 4) or ISLH testing, their applicability is at all times in keeping with the concern for non-ductile failure.

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BASES (continued)

APPLICABILITY (continued)

During MODES 1 and 2, other LCOs provide limits for operation that can be more restrictive than these P/T limits. These LCOs are LCO 3.4.1, "Recirculation Loops Operating," and LCO 3.4.10, "Reactor Steam Dome Pressure." Safety Limit 2.1, "Safety Limits," also gives operational restrictions for P/T and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for non-ductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

The Actions designated by this specification are based on the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, which may be accompanied by equipment failures, may also require additional Actions based on emergency operating procedures.

A.1 and A.2

Operation not within the P/T limits must be restored to within the limits. The RCPB must be placed in a condition that has been verified by stress analyses. Restoration is in the proper direction to reduce RCPB stress.

The 30-minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. The evaluation must be

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BASES (continued)

ACTIONS (continued)

completed, documented, and approved in accordance with established plant procedures and administrative controls.

ASME Section XI, Appendix E (Ref. 6) may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline. The evaluation must extend to all components of the RCPB.

The 72-hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event-specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring both Required Action A.1 and Required Action A.2 completed whenever the condition is entered. The Note emphasizes the need to restore operation within limits and perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone is insufficient because higher-than-analyzed stresses may have occurred and may have affected the RCPB integrity.

The combination of RCS P/T is considered out of limits if the equipment used to measure RCS pressure or temperature is determined to be inoperable. Required Action A.1 and Required Action A.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because: a) the RCS remained in an unacceptable P/T region for an extended period of increased stress, or b) a sufficiently severe event caused drastic entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced P/T. With the reduced conditions, the possibility of propagation of undetected flaws is decreased.

If the restoration activity cannot be accomplished in 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce P/T.

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BASES (continued)

ACTIONS (continued)

If the evaluation for continued operation cannot be accomplished in 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce P/T as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed, documented, and approved before returning to operating P/T conditions. However, if the favorable evaluation is accomplished while reducing P/T conditions, a return to power operation may be considered without completing Required Action B.1 and Required Action B.2.

P/T are reduced by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

The 36-hour Completion Time for achieving MODE 5 permits a soak period, if needed, or a slower cooldown [(~5°F/hr)]. A soak period may be desirable if a temperature rate of change limit has been violated.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within LCO limits is required every 30 minutes when RCS temperature and pressure conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate-of-change limits are specified in hourly increments, 30 minutes permit a reasonable time for assessment and correction of minor deviations.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

A Note requires this surveillance to be performed only during system heatup, cooldown, and ISLH testing.

[For this facility, RCS P/T is measured as follows:]

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.9.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS P/T must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before rod withdrawal for achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.9.3 and SR 3.4.9.4

Differential temperatures within the applicable LCO limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 9) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

A Note requires SR 3.4.9.3 to be performed in MODES 1, 2, and 3, and in MODE 4 with reactor steam dome pressure ≥ 25 psig. A Note also requires SR 3.4.9.4 to be performed only in MODES 1, 2, 3, and 4.

[For this facility, bottom head coolant temperature is measured as follows:]

[For this facility, RPV coolant temperature is measured as follows:]

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.9.5

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits. Surveillances must be performed every 30 minutes while approaching and early in MODE 4, then every 12 hours until reaching the specified RCS temperature to stay abreast of changes.

The flange temperatures must be verified above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature less than or equal to 80°F, 30-minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature less than or equal to 100°F, Surveillances of the flange temperatures are required every 12 hours to ensure the temperatures are within the limits specified in the PTLR.

The 30-minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12-hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix G, "Fracture Toughness Requirements."

2. ASME Boiler and Pressure Vessel Code, Section III, Appendix G, "Protection Against Non-Ductile Failure."

3. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

4. NUREG-0800, USNRC Standard Review Plan, Section 5.3.1, "Reactor Vessel Materials," Rev. 1, July 1981.

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BASES (continued)

REFERENCES (continued)

5. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," July 1982.

6. Title 10, Code of Federal Regulations, Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

7. ASME Boiler and Pressure Vessel Code, Section XI, Appendix E, "Evaluation of Unanticipated Operating Events."

8. NEDO-21778-A, "Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

9. [Unit Name] FSAR, Section [15], "[Title]," [Subsection 15.1.26].

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed initial condition of Design Basis Accidents (DBAs) and transients and is also an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ [1020] psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of DBAs and transients used to determine the limits for fuel cladding integrity (MINIMUM CRITICAL POWER RATIO, see Bases for LCO 3.2.2) and 1% cladding plastic strain (see Bases for LCO 3.2.1). References 1 and 2 contain the acceptance limits for the associated DBAs and transients. They are referred to when making modifications to the unit which could affect the reactor steam dome pressure to assess any effect in relation to the acceptance limits. Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Interim Policy Statement.
LCO	The specified reactor steam dome pressure limit of ≤ [1020] psig assures the plant is operated within the assumptions of the transient analyses. Operation above the limit may result in a transient response more severe than analyzed.

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BASES (continued)

LCO (continued)

The system is OPERABLE when:

a. All components necessary to provide the function are functional and in service; and

b. All required surveillances are current and have demonstrated acceptable performance.

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES the reactor may be generating significant steam and the DBAs and transients are bounding. The limit may be exceeded during anticipated operational occurrences; however, the evaluations of References 1 and 2 demonstrate that appropriate reactor and fuel limits are not exceeded.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15-minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also accounts for the unlikely probability of an accident occurring while pressure is greater than the limit. If the operator is unable to restore the reactor steam dome pressure to below the limit, then the reactor should be placed in MODE 3 to be operating within the assumptions of the transient analyses.

Reactor steam dome pressure is considered out of limits if the equipment used to measure reactor steam dome pressure is determined to be inoperable. Required Action A.1 applies to restoring such equipment to OPERABLE status.

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BASES (continued)

ACTIONS (continued)

B.1

The plant must be placed in a MODE in which the LCO does not apply if the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours. This Completion Time is reasonable, based on operating experience, to reach the required MODE from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is ≤ [1020] psig ensures that the initial conditions of the DBAs and transients are met. Operating experience has shown the 12-hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

[For this facility, reactor steam dome pressure is measured as follows:]

REFERENCES

1. [Unit Name] FSAR, Section [5.2.2.2.4.], "[Title]."

2. [Unit Name] FSAR, Section [15], "[Accident Analyses]."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

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 uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the low pressure coolant injection (LPCI) subsystem of the Residual Heat Removal (RHR) System, and 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 the HPCI and CS systems.

On receipt of an initiation signal, all 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, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory while the RCS is still pressurized and, thus, maintain vessel level. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, ADS timed sequence would be allowed to time out and open the selected safety/relief valves (S/RVs) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly and the LPCI and CS cool the core.

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 Standby

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BASES (continued)

BACKGROUND (continued)

Service Water System (SWS). Depending on the location and size of the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break. Although no credit is taken in the safety analysis for the RCIC System, it performs the same function as HPCI, but has limited makeup capability. Nevertheless, it will maintain inventory and cool the core while the RCS is still pressurized following a reactor pressure vessel (RPV) isolation.

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 equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor-driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started (from normal AC power if available; otherwise, the pumps start after emergency AC power becomes available). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS system without spraying water in the RPV.

LPCI is an independent operating mode of the RHR system. There are two LPCI subsystems (Ref. 2), each consisting of two motor-driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop. The two LPCI subsystems can be interconnected via the RHR System cross-tie valve; however, the cross-tie valve is maintained closed with its power removed to prevent loss of both LPCI subsystems during a LOCA. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically started (from normal AC power, if available; otherwise, the pumps start after emergency AC power becomes available). RHR System

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BASES (continued)

BACKGROUND (continued)

valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for the four LPCI pumps to route water from the suppression pool to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) 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, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. If the CST water supply is low, however, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (162 to 1135 psid, vessel to pump suction). Actuation of HPCI relies only on its DC power source. Upon receipt of an initiation signal from [RPV low water level], the HPCI turbine stop valves and turbine control valves open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

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

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BASES (continued)

BACKGROUND (continued)

overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water-hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS System discharge lines are kept full of water using a "keep fill" system (jockey pump system). The HPCI System is normally aligned to the CST. The height of water in the CST is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water. Therefore, HPCI does not require a keep fill system.

The ADS (Ref. 4) consists of [7] of the [11] S/RVs. It is designed to provide depressurization of the RCS during a small-break LOCA if HPCI fails or is 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 (CS and LPCI), so that these subsystems can provide coolant inventory makeup. Each of the S/RVs used for automatic depressurization is equipped with one air accumulator and associated inlet check valves. The accumulator provides the pneumatic power to actuate the valves.

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 Reference 5. The required analyses and assumptions are defined in Reference 6. The results of these analyses are also described in Reference 5.

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 ≤ 2200°F;

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

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

c. Maximum hydrogen generation from a zirconium-water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders 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 8. For a large discharge pipe break LOCA, failure of the LPCI injection valve on the unbroken recirculation loop is considered the most severe failure. For a small-break LOCA, HPCI failure is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

All ECCS subsystems and [seven] ADS valves are required to be OPERABLE. The ECCS subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low-pressure ECCS subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With fewer than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst-case single failure, the limits specified in Reference 7 could be exceeded. All ECCS subsystems must therefore be properly aligned, tested, maintained, and supported by appropriate support systems to be OPERABLE and to satisfy the single failure criterion required by Reference 7. The ECCS is supported by other systems that provide automatic ECCS initiation signals (LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation"); service water to cool pumps and ECCS equipment rooms (LCO 3.7.3, "[Plant] Service Water (PSW) System and Ultimate Heat Sink (UHS)"); electrical power

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BASES (continued)

LCO (continued)

(LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.3, "DC Sources—Operating"); suppression pool cooling (Standby SWS); and pneumatic power (ADS instrument air supply).

A LPCI subsystem may be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below the RHR cut-in permissive pressure in MODE 3, if capable of being manually realigned from the control room to the LPCI 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.

[For this facility, an OPERABLE HPCI System constitutes the following:]

[For this facility, an OPERABLE LPCI subsystem constitutes the following:]

[For this facility, an OPERABLE CS subsystem constitutes the following:]

[For this facility, an OPERABLE ADS valve constitutes the following:]

[For this facility the following support systems are required to be OPERABLE to ensure ADS valve OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the ECCS subsystems or ADS valves inoperable and their justification are as follows:]

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, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low-pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2.

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BASES (continued)

APPLICABILITY (continued)

A Note has been added to provide clarification that, for this LCO, all ECCS subsystems and all ADS valves are treated as an entity with a single Completion Time.

ACTIONS

A.1

If any one low-pressure ECCS subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. Overall ECCS reliability is reduced, however, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7-day Completion Time is based on a reliability study (Ref. 9) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs).

B.1 and B.2

If the inoperable low-pressure ECCS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is immediately verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is assured by the OPERABILITY of the redundant and diverse low pressure ECCS

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BASES (continued)

ACTIONS (continued)

subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check or by examining logs or other information to determine that the RCIC System is OPERABLE.

The verification does not require the performance of the SRs needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be immediately verified, however, Condition G must be immediately entered.

If a single active component fails concurrent with a LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14-day Completion Time is based on a reliability study cited in Reference 9 and has been found to be acceptable through operating experience.

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

If any one low-pressure ECCS subsystem is inoperable in addition to an inoperable HPCI System, and the RCIC System is immediately verified to be OPERABLE, the inoperable low-pressure subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low-pressure ECCS subsystems; however, the ECCS reliability is significantly reduced. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine that the RCIC System is OPERABLE. The verification does not require the performance of the SRs needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of RCIC System cannot be immediately verified, however, Condition G must be immediately entered. If a single active component failure occurs concurrent with a design basis LOCA, the minimum required ECCS equipment will not be available. Since both a high-pressure system (HPCI) and a low-pressure subsystem are inoperable a more restrictive Completion Time

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BASES (continued)

ACTIONS (continued)

of 72 hours is allowed to restore either the HPCI System or the low-pressure ECCS subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 9 and has been found to be acceptable through operating experience.

E.1

The LCO requires [seven] ADS valves to be OPERABLE to provide the ADS function. Reference 10 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. As per this analysis, operation of only [six] ADS valves will provide the required depressurization. The overall reliability of the ADS is reduced, however, and operation is only allowed for a limited time. The 14-day Completion Time is based on a reliability study cited in Reference 9 and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low-pressure ECCS subsystem is inoperable in addition to one inoperable required ADS valve, adequate core cooling is assured by the OPERABILITY of HPCI and the remaining low-pressure ECCS subsystem; however, ECCS reliability is further reduced. If a single active component failure occurs concurrent with a design basis LOCA, the minimum required ECCS equipment may not be available. Since both a high-pressure system (ADS) and a low-pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is allowed to restore either the low-pressure ECCS subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study, cited in Reference 9, and has been found to be acceptable through operating experience.

G.1 and G.2

The plant must be placed in a Condition in which the LCO does not apply if the Required Actions and associated Completion Times of Condition C, D, E, or F are not met, or if two or more required ADS valves are inoperable. This is done by placing the plant in at least MODE 3 within 12 hours and reducing reactor steam dome pressure to ≤ 150 psig

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BASES (continued)

ACTIONS (continued)

within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODE and condition from full power in an orderly manner and without challenging plant systems.

H.1

When multiple ECCS subsystems are inoperable, as stated for Condition H, the plant is in a Condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

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 HPCI System, CS system, and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are "full" is to vent at the high points. The 31-day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.

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 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 non-accident 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 being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned,

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

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 position 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 an LPCI subsystem to be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below the RHR cut-in permissive pressure in MODE 3, if capable of being manually realigned from the control room to the LPCI 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 [air supply header] pressure is ≥ [90] psig ensures air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 8). 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 ≥ [90] psig is provided by the ADS instrument air supply. The 31-day Frequency takes into consideration administrative controls over operation of the air system and alarms for low air pressure.

SR 3.5.1.4

Verification every 31 days that the RHR System cross-tie valve is closed and power to its operator is disconnected ensures that each LPCI subsystem remains independent and a failure of the flow path in one subsystem will not affect

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include de-energizing breaker control power or racking out or removing the breaker. If the RHR System cross-tie valve is open or power has not been removed from the valve operator, both LPCI subsystems must be considered inoperable. The 31-day Frequency has been found acceptable, considering that these valves are under strict administrative controls that will ensure that valves continue to remain closed with either control or motive power removed.

SR 3.5.1.5

Verification every 31 days that each LPCI inverter output has a voltage of ≥ [570] and ≤ [630] volts while supplying its respective bus demonstrates that the AC electrical power is available to ensure proper operation of the associated LPCI inboard injection and minimum flow valves and the recirculation pump discharge valve. Each inverter must be OPERABLE for the associated LPCI subsystem to be OPERABLE. [For this facility, the 31-day Frequency is justified as follows:]

SR 3.5.1.6

Cycling the recirculation pump discharge (and bypass) valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will close when required. Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to be closed to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for the LPCI subsystem. Acceptable methods of de-energizing the valve include de-energizing breaker control power or racking out or removing the breaker. This test must be performed once each reactor startup prior to THERMAL POWER reaching > 25% RATED THERMAL POWER (RTP) if not performed within the previous 31 days. If the valve is inoperable and in the open position, the associated LPCI subsystem must be declared inoperable.

Verification during reactor startup prior to reaching > 25% RTP is an exception to the normal Inservice Testing Program generic valve cycling Frequency of 92 days, but is

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

considered acceptable due to the demonstrated reliability of these valves.

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9

The performance requirements of the low-pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 6). Periodic surveillance is performed (in accordance with the American Society of Mechanical Engineers (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 low-pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 7. The pump flow rates are verified against a system head 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 a LOCA. These values may be established during preoperational testing.

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow is tested at both the higher and lower operating ranges of the system. Since the reactor steam dome pressure must be ≥ [920] psig to perform SR 3.5.1.8 and ≥ [150] psig to perform SR 3.5.1.9, sufficient time is allowed after adequate pressure is achieved to perform these tests once only. Reactor startup is allowed prior to performing the low-pressure test because the reactor pressure is low and the time allowed to satisfactorily perform the test is short. The reactor pressure is allowed to be increased to normal operating pressure because the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable. Thus, a Note is included in SR 3.5.1.8 to indicate that SR 3.0.4 does not apply.

A 92-day Frequency for SR 3.5.1.7 and SR 3.5.1.8 is in accordance with the Inservice Testing Program and must not be exceeded. The 18-month Frequency for SR 3.5.1.9 was developed considering plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

experience has shown that these components usually pass the SR when performed on the 18-month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.10

The ECCS subsystems are required to actuate automatically to perform their design functions. These surveillance tests demonstrate that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures that the HPCI System will automatically restart on an RPV low water level (Level 2) 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.

The 18-month Frequency was developed considering plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 tests. 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 tests.

SR 3.5.1.11

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test (logic only) is performed to demonstrate that the ADS logic operates as designed when

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 3.5.1.12

A manual actuation of each ADS valve is performed to verify that the valve and solenoid 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 or 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 once only. Adequate pressure at which this test is to be performed is [920] psig (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. Thus, a Note is included in this SR to indicate that SR 3.0.4 does not apply.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [6.3.2.2.3], "[Title]."

2. [Unit Name] FSAR, Section [6.3.2.2.4], "[Title]."

3. [Unit Name] FSAR, Section [6.3.2.2.1], "[Title]."

4. [Unit Name] FSAR, Section [6.3.2.2.2], "[Title]."

5. [Unit Name] FSAR, Section [6.3.3], "[Title]."

6. Title 10, Code of Federal Regulations, Part 50, Appendix K, "ECCS Evaluation Models."

7. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors."

8. [Unit Name] FSAR, Section [7.3.1.2.2], "[Title]."

9. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

10. [Unit Name] FSAR, Section [6.3.3.3], "[Title]."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 ECCS—Shutdown

BASES

BACKGROUND

A description of the Core Spray (CS) System and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases B 3.5.1 also applies to this Bases section. The 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. 1) demonstrates that only one low-pressure ECCS subsystem is required, post-LOCA, to maintain the peak cladding temperature below the allowable limit. To preserve the single failure criterion of Reference 2, a minimum of two low-pressure ECCS subsystems are required to be OPERABLE in MODES 4 and 5. Two OPERABLE low-pressure ECCS subsystems also ensure adequate vessel inventory makeup in the event of an inadvertent vessel draindown.

The low-pressure ECCS subsystems satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Two low-pressure ECCS subsystems are required to be OPERABLE. The low-pressure ECCS subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of two motor-driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the reactor pressure vessel (RPV). Each LPCI subsystem consists of one motor-driven pump, piping, and valves to transfer water from the suppression pool to the RPV. Only a single LPCI pump is required per subsystem because of the larger injection capacity in relation to a CS subsystem. Support systems affecting the OPERABILITY of the ECCS are discussed in the LCO 3.5.1

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BASES (continued)

LCO (continued)

Bases. In MODES 4 and 5, the RHR System cross-tie valve is not required to be closed.

One LPCI subsystem may be aligned in the shutdown cooling mode of the RHR System in MODE 4 or 5 and considered OPERABLE for the ECCS function, if it can be manually realigned from the control room to the LPCI 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 LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. Support systems affecting the OPERABILITY of the ECCS are discussed in the LCO section of Bases B 3.5.1.

[For this facility, an OPERABLE CS subsystem constitutes the following:]

[For this facility, an OPERABLE LPCI subsystem constitutes the following:]

[For this facility, those required support systems which, upon their failure, do not require declaring the ECCS subsystems inoperable and their justification are as follows:]

APPLICABILITY

OPERABILITY of the low-pressure ECCS 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 Bases B 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the cavity flooded, the spent fuel storage pool gates removed, and the water level maintained at ≥ 23 feet 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.

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BASES (continued)

APPLICABILITY (continued)

The Automatic Depressurization System (ADS) is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is ≤ 150 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection (HPCI) System is not required to be OPERABLE during MODES 4 and 5 since the low-pressure ECCS subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low-pressure ECCS subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status in 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. Overall system reliability is reduced, however, because a single failure in the 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 low-pressure ECCS subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, 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 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

With both of the required ECCS subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs to minimize the probability of a vessel draindown and

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BASES (continued)

ACTIONS (continued)

the subsequent potential for fission-product release. Actions must continue until OPDRVs are suspended. If at least one low-pressure ECCS subsystem is not restored to OPERABLE status within the 1-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, one secondary containment isolation valve, and associated instrumentation in each associated penetration not isolated. OPERABILITY may be verified by an administrative check or by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. Verification does not require performing the SRs 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, SRs may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

The 1-hour Completion Time to restore at least one low pressure ECCS subsystem (injection or spray) to OPERABLE status ensures that prompt action is 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 [12 ft 2 inches] required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS System and LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS subsystems are inoperable unless they are aligned to an OPERABLE CST.

When suppression pool level is less than [12 ft 2 inches], the CS System is considered OPERABLE only if it can take

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CS pump. Therefore, a verification that either the suppression pool water level is ≥ [12 ft 2 inches] or that CS is aligned to take suction from the CST and the CST contains ≥ [150,000] gallons of water, equivalent to 12 ft, ensures that the CS System can supply at least [50,000] gallons of makeup water to the RPV. The CS suction is uncovered at the [100,000]-gallon level.

The 12-hour Frequency of these SRs was developed considering operating experience related to suppression pool water level 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 available in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

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 3.5.1.7, and SR 3.5.1.10 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 non-accident 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 LPCI subsystem operation may be aligned for the shutdown cooling mode.

This SR is modified by a Note that allows one LPCI subsystem of the RHR to be considered OPERABLE for the ECCS function if all the required valves in the LPCI flow path can be manually realigned from the control room to allow injection into the RPV, and the system is not otherwise inoperable. This will ensure adequate core cooling if an inadvertent RPV draindown should occur.

REFERENCES

1. [Unit Name] FSAR, Section [6.3.2], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS. The RCIC System is included with the ECCS section because of similar functions.

The RCIC System is 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 the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System 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, where the coolant is distributed within the RPV through the feedwater sparger. 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. If the CST water supply is low or the suppression pool level is high, however, an automatic transfer to the suppression pool ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from a steam line upstream of the associated inboard steam line isolation valve. (Ref. 2)

The RCIC System is designed to provide core cooling over a wide range of reactor pressures [165 to 1155 psig]. Upon receipt of an initiation signal from low RPV water level, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve (TCV) 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 CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

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BASES (continued)

BACKGROUND (continued)

The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valves in this line automatically open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water-hammer effects, the RCIC System discharge piping is kept full of water. The RCIC System is normally aligned to the CST. The height of water in the CST is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep fill" system.

APPLICABLE SAFETY ANALYSES

The function of the RCIC System to provide makeup coolant to the reactor is used to respond to transient events. The RCIC System is not an Engineered Safety Feature (ESF) System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system is included in the Technical Specifications, as encouraged by the NRC Interim Policy Statement.

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the low-pressure ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event.

[For this facility, an OPERABLE RCIC System constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure RCIC System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RCIC System inoperable and their justification are as follows:]

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BASES (continued)

APPLICABILITY

The RCIC System is required to be OPERABLE in MODES 1, 2, and 3 with reactor steam dome pressure > 150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the low-pressure ECCS subsystems can provide sufficient flow to the RPV.

ACTIONS

A.1 and A.2

If the RCIC System is inoperable during MODE 1, 2, or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high-pressure system assumed to function during a loss-of-coolant accident (LOCA). OPERABILITY of HPCI is therefore immediately verified when the RCIC System is inoperable. This may be performed by an administrative check, by examining logs or other information, to determine if the HPCI System is OPERABLE. Verification does not require performing the SRs needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be immediately verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The ECCS Completion Times are based on the results of a study that evaluated the impact on ECCS availability assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). AOTs were then chosen to provide comparable levels of ECCS availability throughout the industry (Ref. 3).

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BASES (continued)

ACTIONS (continued)

Because of similar functions of HPCI and RCIC, the AOTs determined for HPCI are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status in the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be placed in a Condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and reducing reactor steam dome pressure to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODE and condition from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an 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 the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power-operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC 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 non-accident 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 being

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position. 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 position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. 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 3.5.3.3 and SR 3.5.3.4, sufficient time is allowed after adequate pressure is achieved to perform these tests once only. Reactor startup is allowed prior to performing the low-pressure test because the reactor pressure is low and the time allowed to satisfactorily perform the test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low-pressure test for ECCS pumps has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Thus, a Note is included in SR 3.5.3.3 to indicate that SR 3.0.4 does not apply.

A 92-day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 18-month Frequency for SR 3.5.3.4 was developed considering plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Based on operating experience, the 12 hours allowed to demonstrate that the RCIC pump can deliver the rated flow under high and low pressure is sufficient.

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This surveillance test demonstrates that with a required system initiation signal, actual or simulated, the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence, that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on a RPV low water level (Level 2) signal received subsequent to a RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool.

The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed on 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 test. 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 test.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 33, "Reactor Coolant Makeup."
2. [Unit Name] FSAR, Section [5.5.6], "[Title]."

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BASES (continued)

REFERENCES (continued)	3.	Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

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 within the requirements of 10 CFR 100 (Ref. 1) or the NRC Staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). 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 radioactivity to the environment.

To ensure primary containment is OPERABLE, leakage test requirements have been set forth by Reference 2. These test requirements provide for periodic verification by tests of the leak-tight integrity of the primary containment and of the systems and components that penetrate the primary containment. The purpose of the leakage tests is to ensure that leakage through the primary containment and through systems and components penetrating the primary containment shall not exceed the allowable leakage rates specified in the technical specification and used in the safety analyses. Additionally, the periodic tests performed ensure that proper maintenance and repairs are made during the service life of the plant.

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 3 and 4. All leakage-rate requirements and SRs are in conformance with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that the primary containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate, such that, in conjunction with the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

other Containment systems and ENGINEERED SAFETY FEATURE (ESF) systems, the release of fission-product radioactivity subsequent to a DBA will not result in doses in excess of the values given in the licensing basis.

The DBA that results in a release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE at event initiation 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 Reference 3 and 4. The safety analyses assume a non-mechanistic fission-product release following a DBA that 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, and that the site boundary radiation dose will not exceed the limits of 10 CFR 100 (Ref. 1) even if the non-mechanistic release were to occur.

All leakage-rate requirements and SRs are in conformance with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions as contained in the Primary Containment Leakage Rate Testing Program. The maximum allowable leakage rate for the primary containment (L_a) is [1.2]% by weight of the Containment air per 24 hours at P_a, [57.5] psig, or [0.84]% by weight of the Containment air per 24 hours at the reduced pressure of P_t, [28.8] psig (Ref. 4). The maximum allowable leakage rate is based on what is acceptable for nuclear safety considerations per 10 CFR 100 (Ref. 1). Reactor size, site location, and meteorology, as well as the possible mechanisms for radioactivity generation and transport, are all considered in specifying the allowable leakage rate for a given Containment system. For this unit, L_a = [ ]% per day and P_a = [ ] psig, resulting from the limiting design basis LOCA (Ref. 4).

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset of the postulated fission-product release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 1) are a whole body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

Primary containment satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The requirements stated in this LCO define the performance of the primary containment fission-product barrier. The containment design leakage rate (L_a) is an assumed initial condition. Primary containment OPERABILITY is maintained by limiting leakage to within the acceptance criteria of 10 CFR 50, Appendix J (Ref. 2).

The primary containment LCO requires that primary containment OPERABILITY be maintained. Other containment LCOs support this LCO by ensuring that:

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 deactivated automatic valves secured in their closed positions, except as provided in Reference [ ];

b. All equipment hatches are closed;

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BASES (continued)

LCO (continued)

c. The primary containment air lock is OPERABLE (see LCO 3.6.1.2, Condition C, Note 1);

d. The primary containment leakage rates are within their limits as defined in the Primary Containment Leakage Rate Testing Program;

e. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE; and

f. [The structural integrity of the primary containment is ensured by the successful completion of the Primary Containment Tendon Surveillance Program and by associated visual inspections of the steel liner and penetrations for evidence of deterioration or breach of integrity].

The Required Actions when other primary containment LCOs are not met have been specified in these LCOs and not in LCO 3.6.1.1.

Compliance with LCO 3.6.1.1 will ensure a primary containment configuration that is structurally sound and will limit leakage to those leakage rates assumed in the safety analyses. As a result, offsite radiation exposures will be maintained within the limits of 10 CFR 100 (Ref. 1), or NRC staff-approved licensing basis, following the most limiting DBA. The provisions of this LCO as delineated in the above definition are implemented as follows.

a. OPERABILITY and status of primary containment penetrations:

1. The OPERABILITY of valves that are closed or are required to close in response to a Containment isolation signal is ensured by compliance with the SRs of LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," and 10 CFR 50, Appendix J (Ref. 2), as defined in the Primary Containment Leakage Rate Testing Program. Some of the valves that must be closed to meet the accident analysis assumptions may be opened on an intermittent basis under administrative controls. These valves are identified in Reference [ ]. The Required Actions and SRs of LCO 3.6.1.3 ensure

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BASES (continued)

LCO (continued)

that the associated PCIVs close within the required time limit, that the affected penetration is isolated by closed isolation valves or blind flanges, or that the plant is shut down. In addition, the Type C tests required by SR 3.6.1.1.1 and Appendix J require that these PCIVs meet specified leakage-rate criteria, namely, that the combined leakage rate for all penetrations and valves subject to Type B and C tests shall be less than 0.6 L_a.

2. The status of primary containment penetration isolation valves that are required to be closed during accident conditions, and do not close automatically, is verified by SRs 3.6.1.3.1, 3.6.1.3.2, 3.6.1.3.3, and 3.6.1.3.4. The valves that must be closed to meet the accident analysis assumptions may be opened on an intermittent basis under administrative controls.

b. The OPERABILITY of the primary containment equipment hatch is ensured by compliance with the leakage criteria established by 10 CFR 50, Appendix J (Ref. 2).

c. The OPERABILITY of the primary containment air lock, required by LCO 3.6.1.2, "Primary Containment Air Lock," requires that at least one door in each air lock be closed during MODES 1, 2, and 3, that the air locks satisfy the 10 CFR 50, Appendix J (Ref. 2), leakage-test requirements as described in the Primary Containment Leakage Rate Testing Program, and that the door interlocks function as required.

d. Containment leakage-rate requirements are contained in 10 CFR 50, Appendix J (Ref. 2), and the Primary Containment Leakage Rate Testing Program. These requirements are implemented to ensure that the primary containment as a whole, as well as each of its penetrations and isolation valves, does not exceed its specified leakage rate.

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BASES (continued)

LCO (continued)

e. The successful completion of all the leakage-testing requirements stipulated in 10 CFR 50, Appendix J (Ref. 2), is necessary to ensure the OPERABILITY of penetration sealing mechanisms.

The measures implemented to meet the above requirements provide assurance that the primary containment will perform its designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to 10 CFR 100 (Ref. 1) guidelines, or some fraction established in the NRC staff-approved licensing basis.

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 in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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BASES (continued)

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. 2), as modified by approved exemptions and as described in the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage-rate testing requirements with regard to overall primary containment leakage (Type A leakage tests); leakage from equipment hatch, electrical penetrations, and other penetrations except air lock (Type B leakage tests); and leakage from PCIVs, except [ ]-inch purge valves (Type C leakage tests). These periodic testing requirements verify that the primary containment leakage rate does not exceed the leakage rate assumed in the safety analyses. Leakage-rate testing of the primary containment purge valves is addressed in LCO 3.6.1.3, "Primary Containment Isolation Valves." Air-lock door seal leakage testing is addressed in LCO 3.6.1.2. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), identified in the Primary Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.1.2

The structural integrity of the primary containment is assured by the successful completion of the Primary Containment Tendon Surveillance Program and by associated visual inspections of the steel liner and penetrations for evidence of deterioration or breach of integrity that ensures that the structural integrity of the primary containment will be maintained in accordance with the provisions of the Primary Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 5).

SR 3.6.1.1.3

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell-to-suppression-chamber differential pressure during a 10-minute period to ensure that the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this Surveillance can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and verifying that the pressure in either the suppression chamber or the drywell does not change by more than 0.25 inches of water per minute over a 10-minute period. The leakage test is performed every 18 months. The 18-month Frequency was developed considering it was prudent that this Surveillance be performed during a plant 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, increasing the Frequency to once every 9 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

2. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

3. [Unit Name] FSAR, Section [ ], "[Title]."

4. [Unit Name] FSAR, Section [ ], "[Containment Systems]."

5. Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

One double-door primary containment air lock has 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 lock is designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment in order to maintain primary containment OPERABILITY (Ref. 3). As part of the primary containment, the air lock limits the release of radioactive material to the environmentring normal plant operation and through a range of incidents 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. As such, closure of a single door supports primary containment OPERABILITY. 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, 10 feet in diameter, with doors at each end that are interlocked to prevent simultaneous opening. The air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air-lock-door interlock mechanism is defeated. During periods when primary containment is not required to be OPERABLE, the door 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 interlock mechanism has failed by manually performing the interlock function.

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BASES (continued)

BACKGROUND (continued)

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and air tightness is essential to limit offsite doses from a DBA. Not maintaining air lock integrity or air tightness may result in offsite doses in excess of those described in the plant safety analyses. All leakage-rate requirements and SRs conform with 10 CFR 50, Appendix J (Ref. 1), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

Primary containment OPERABILITY, and the limiting of radioactive release to the environment, is a consideration in the evaluation of a number of accident analyses. For example, the loss-of-coolant accident (LOCA) analysis requires a primary containment boundary to ensure that the site boundary radiation dose will not exceed the limits of 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). As delineated in 10 CFR 100 (Ref. 2), the determination of exclusion areas and low-population zones surrounding a site must consider a fission-product release from the core with offsite release based on the expected demonstrable leakage rate from the primary containment.

The DBA that results in a release of radioactive material within primary containment is a LOCA (Ref. 3). In the analysis of each of these accidents, it is assumed that primary containment is OPERABLE at event initiation, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment was designed with an allowable leakage rate of [0.1]% of containment air weight per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a [unit-specific #]: the maximum allowable containment leakage rate at the calculated maximum peak Containment pressure (P_a [unit specific #] following a DBA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. The acceptance criteria applied to DBA releases

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following onset of the postulated fission-product release; or

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission-product gases that may bypass primary containment and contaminate and pressurize the secondary containment.

Closure of a single door in each air lock is sufficient to support primary containment OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry and exit from primary containment.

The primary containment air lock satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

As part of primary containment, the air lock's safety function is related to control of offsite radiation exposures resulting from a DBA. Thus, the air lock's structural integrity and leakage tightness are essential to the successful mitigation of such an event.

The air lock is required to be OPERABLE. For the 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 allows only one air-lock

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BASES (continued)

LCO (continued)

door of an air lock to be opened at one time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. The closure of a single door in an air lock will maintain primary containment OPERABILITY since each door is designed to withstand the peak primary containment pressure calculated to occur following a DBA.

This LCO provides assurance that the primary containment air lock will perform its designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to 10 CFR 100 limits or some fraction as established in an NRC staff-approved licensing basis.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment air lock OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the primary containment air locks inoperable and their justification are as follows:]

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.

The Required Actions of Condition A, B, or C are modified by a Note that allows entry and exit to perform repairs on 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 a short time exists when the 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

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BASES (continued)

APPLICABILITY (continued)

which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

An additional Note has been included to provide clarification that the primary containment air lock is treated as an entity for this LCO with a single Completion Time.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one air-lock door inoperable, the OPERABLE door must be verified closed and remain closed in the air lock. This assures 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 Required Actions of LCO 3.6.1.1, "Primary containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the inoperable door in the air lock must be restored to OPERABLE status or the air-lock penetration must be isolated by locking closed the OPERABLE air-lock door. One of these two Required Actions must be completed within the 24-hour Completion Time. The 24-hour Completion Time is considered reasonable for restoring the air-lock door to OPERABLE status, considering that the OPERABLE door is being maintained closed.

Required Action A.2.2.2 verifies that the air lock 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 leakage rate acceptance criteria are defined in SR 3.6.1.2.1. The periodic interval of 31 days is based on engineering judgment and considered adequate since other administrative controls, such as indications of interlock mechanism status, are available to the operator to ensure that the OPERABLE air-lock door remains closed.

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BASES (continued)

ACTIONS (continued)

B.1, B.2.1, B.2.2.1, and B.2.2.2

With an air-lock door interlock mechanism inoperable, the Required Actions and associated Completion Times consistent with Condition A are applicable.

Condition B is modified by a Note that allows entry and exit through an air lock under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at the time and to ensure that the opened door is immediately closed.

C.1 and C.2

If the air lock is inoperable for reasons other than those described in Condition A or B, one door in the primary containment air lock must be verified closed. This action must be completed within the 1-hour Completion Time. This specified time period is consistent with the Required Actions of LCO 3.6.1.1, "primary containment," which requires 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 the air lock.

The Required Actions of Condition C are modified by a Note that requires the primary containment to be declared inoperable should both doors in an air lock fail the air-lock door seal test, SR 3.6.1.2.1.

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 placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours.

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BASES (continued)

ACTIONS (continued)

The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODES from full power 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, as modified by approved exemptions and as described in the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage-rate testing requirements with respect to air-lock leakage (Type B leakage tests). The acceptance criteria are described in the Facility Leakage Rate Test Program. 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, as modified by approved exemptions, and is described in the Primary Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

The SR has been modified by a Note indicating that an inoperable air-lock door does not invalidate the previous successful performance of an 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.

SR 3.6.1.2.2

The air-lock door interlock 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 ensure primary containment OPERABILITY. Thus, the door interlock feature ensures that primary containment OPERABILITY is maintained while the air lock is being used for personnel transit in and out of the containment. Periodic testing of

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 prior to 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 the operations personnel.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

3. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The PCIVs, in combination with other accident-mitigation systems, is to limit fission-product release during and following postulated Design Basis Accidents (DBAs) to values less than 10 CFR 100 (Ref. 9) offsite dose limits that are part of the NRC staff-approved licensing basis. 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). Locked-closed manual valves, deactivated 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. Closed systems are those systems designed in accordance with GDC 57 (Ref. 2). Check valves, or other automatic valves designed to close following an accident without operator's action, 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 (and possibly loss of primary containment OPERABILITY) or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system inside primary containment (in accordance with the requirements of 10 CFR 50, Appendix A, GDC 57)

Primary containment isolation occurs upon receipt of a high Containment pressure or a low Reactor Coolant System (RCS) pressure signal. The primary containment isolation signal closes automatic PCIVs in fluid penetrations not required

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BACKGROUND (continued)

for operation of ENGINEERED SAFETY FEATURE (ESF) systems in order to prevent leakage of radioactive material. Upon actuation of safety injection, automatic PCIVs also isolate systems not required for primary containment or RCS heat removal. Other penetrations are isolated by the use of valves in the closed position or blind flanges. As a result, the PCIVs (and blind flanges) help ensure that the primary containment atmosphere will be isolated in the event of a release of radioactive material to primary containment atmosphere from the RCS following a DBA. OPERABILITY of the PCIVs (and blind flanges) ensures that primary containment OPERABILITY is maintained during accident conditions.

This primary containment purge system is used to:

a. Vent the primary containment, as necessary, during reactor heatup and normal operation to control primary containment pressure; and

b. Provide clean reactor building air during reactor shutdown and refueling periods to permit personnel access and occupancy.

The primary containment purge lines are [18] inches in diameter; vent lines are [18] inches in diameter. The isolation valves on the [18]-inch vent lines have [2]-inch bypass lines around them for use during normal reactor operation. Two additional redundant excess-flow isolation dampers are provided on the vent line upstream of the Standby Gas Treatment System (SGTS) filter trains. These isolation dampers, together with the PCIVs, will prevent high pressure from reaching the SGTS 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 SGTS 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 [2]-inch bypass line is provided around the dampers. The dampers and isolation valves receive an isolation signal. [For this facility, the isolation signal consists of the following:]. The [18]-inch primary containment purge valves (PCPVs) are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCIV LCO was derived from the requirements related to the control of offsite radiation doses resulting from major accidents. As delineated in 10 CFR 100 (Ref. 9), the determination of exclusion areas and low-population zones surrounding a proposed site must considered a fission-product release from the core, with offsite release based on the expected demonstrable leakage rate from the primary containment. This LCO is intended to ensure that offsite dose limits are not exceeded (the actual primary containment leakage rate does not exceed the value assumed in the safety analyses). As part of the primary containment boundary, PCIV and PCPV OPERABILITY are essential to primary containment OPERABILITY. 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 PCPVs) are minimized. Of the events analyzed in Reference 3, an 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 in 3 to 5 seconds; therefore, the 5-second closure time is assumed in the analysis. The offsite dose calculations 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 acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

a. A member of the general public who remains at the exclusion-area boundary for 2 hours following the onset of the postulated fission-product release; or

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

b. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 (Ref. 9) are a whole-body dose of 25 rem or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use a specified fraction of these limits. The worst-case 2-hour dose anticipated at the exclusion area boundary occurs following the postulated worst-case DBA. The worst-case DBA is a conservative analysis of the LOCA event for which a significant instantaneous release of fission-product radioactivity from the core is postulated.

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 design leakage rate, L_a. The primary containment isolation total 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 plant safety analyses was considered in the original design of the PCPVs. 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 inboard and outboard isolation valves on each line are provided with diverse power sources (motor-operated and pneumatically operated spring closed, respectively). This arrangement was designed to preclude common mode failures from disabling both valves on a purge line.

The PCPVs 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 PCPV due to failure in the control circuit associated with each valve. Again, the PCPV design precludes a single failure from compromising primary containment OPERABILITY as long as the system is operated in accordance with the subject LCO.

The PCIVs and PCPVs satisfy Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to control of offsite radiation exposures resulting from a DBA. This LCO addresses PCIV OPERABILITY, stroke time, and PCPV leakage. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," under Type C testing.

The automatic isolation valves are considered OPERABLE when their isolation times are within limits, the valves actuate on an automatic isolation signal, and excess-flow check valves actuate within the required differential pressure range. The PCPVs have different OPERABILITY requirements. The [42]-inch purge valves must be maintained sealed-closed, and purge valves with resilient seals must meet additional leakage-rate requirements (SR 3.6.1.3.8). Also, purge system valves actuate on an automatic isolation signal. The valves covered by this LCO are listed with their associated stroke times in the FSAR (Ref. 4).

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are locked-closed, automatic valves are deactivated and secured in their closed position (including check valves with flow through the valve secured), and blind flanges and closed systems are in place. Closed systems are those systems designed in accordance with GDC 57 (Ref. 2). These passive isolation valves/devices ar those listed in Reference 5.

Also, OPERABILITY of the containment isolation valves requires OPERABILITY of the following support systems:

a. Engineered Safety Feature Actuation System instrumentation that produces isolation signals (including high primary containment pressure, low RCS pressure, [primary containment radiation—high]) and safety injection system instrumentation;

b. Emergency electrical power; and

c. Instrument air system for pneumatically operated valves.

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(continued)

BASES (continued)

LCO (continued)

This LCO provides assurance that the PCIVs and purge valves will perform their designed safety functions to mitigate the consequences of accidents that could result in offsite exposure comparable to the Reference 9 limits, or some fraction as established in the NRC staff-approved licensing basis.

[For this facility, those required support systems which upon their failure do not declare PCIVs inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a PCIV and the justification of whether or not each supported system is declared inoperable are as follows:]

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 PCPVs 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 3.3.6.1 (not including the excess-flow check valves that isolate the associated instrumentation).

The Applicability is modified by a Note allowing normally locked- and sealed-closed PCIVs, except for purge valves, to be opened 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 valid primary containment isolation signal 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, these valves may not be opened under administrative control. The provisions of LCO 3.0.4 apply.

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BASES (continued)

APPLICABILITY (continued)

A further Note has been added to provide clarification that each penetration flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one or more PCIVs inoperable, at least one isolation valve must be verified to be OPERABLE in each affected open penetration. This action may be satisfied by examining logs or other information to determine whether the valve is out of service for maintenance or other reasons. This Required Action is to be completed within 1 hour in order to provide assurance that a primary containment penetration is not open and causing a loss of primary containment OPERABILITY. The 1-hour Completion Time is consistent with LCO 3.6.1.1, "Primary Containment," and is considered a reasonable length of time needed to complete the Required Action.

In the event that one or more PCIVs are inoperable, either the inoperable valve must be restored to OPERABLE status or the affected penetration 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 deactivated automatic PCIV, a closed manual valve, a blind flange, or a check valve inside primary containment with flow through the valve secured. For penetrations isolated in accordance with Required Action A.2.2.1, the valve used to isolate the penetration should be the closest available valve to primary containment. One of these two Required Actions must be completed within the 4-hour Completion Time. For MSIVs, an 8-hour Completion Time to restore the valve to OPERABLE status is provided. The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of maintaining primary containment integrity during MODES 1, 2, and 3. [For this facility the Completion Time of 8 hours for MSIVS is justified as follows:]

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BASES (continued)

ACTIONS (continued)

For affected penetrations that cannot be restored to OPERABLE status within the applicable Completion Time but have been isolated in accordance with Required Action A.2.2.1, the affected penetrations 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, and which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time for this is once per 31 days for valves outside primary containment and prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4 if not performed more often than once per 92 days for valves inside primary containment. The 31-day Completion Time is based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once per 92 days. 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. For the valves inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4 if not performed more often than once per 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the valves and other administrative controls that will ensure that valve misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is not applicable to those penetrations with only one PCIV and a closed system inside primary containment (i.e., the containment penetration is isolated in accordance with 10 CFR 50 Appendix A, GDC 57, Reference 2). The Required Actions for Condition A assume two valves in series are used to isolate the primary containment penetration and satisfy single failure concerns.

Condition A has been further modified by a Note indicating that this Condition is not applicable to excess-flow check valves that isolate protection systems' instruments. These valves are associated with the Reactor Trip System, the Emergency Core Cooling System, reactor core isolation cooling, PCIVs, secondary containment isolation valves,

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BASES (continued)

ACTIONS (continued)

low-low set safety/relief valves, diesel generators, anticipated transient without scram—recirculation pump trip, or a feedwater/main turbine trip. Since closure of these valves may result in an unplanned transient, and these are all small-diameter lines, more time is provided to repair the associated excess-flow check valves as indicated in Condition B.

Required Action A.1 has been further modified by a Note stating that Required Action A.1 is not applicable to penetrations that have only one isolation valve. Since the Note to Condition A excludes penetrations with only one isolation valve and a closed system, the Note to A.1 refers to penetrations with a single isolation valve on a system that is open inside primary containment but closed outside primary containment. For these systems, if the single isolation valve is inoperable, the intent is to go directly to Required Action A.2.1. These systems are very small piping lines, such as instrument lines, which are closed systems outside of primary containment.

The justification for a Completion Time of 4 hours is analogous to that for lines with two isolation valves. This Note applies only to small lines.

B.1, B.2.1, and B.2.2

With one or more PCIVs inoperable, the inoperable valve(s) must be restored to OPERABLE status or the affected penetration 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 deactivated automatic valve, a closed manual valve, or a blind flange. A check valve may not be used to isolate the affected penetration, since GDC 57 (Ref. 2) does not consider the check valve an acceptable automatic isolation valve. One of these Required Actions must be completed within the 4-hour Completion Time. For excess-flow check valves, a 12-hour Completion Time to restore the valves to OPERABLE status is provided. The specified time period of 4 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a

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ACTIONS (continued)

penetration isolation boundary and the relative importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the relative stability of the closed system (hence reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event that the affected penetration is isolated in accordance with Required Action B.2.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment OPERABILITY is maintained and 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 control and the probability of their misalignment is low.

Condition B is modified by a Note indicating that this Condition is only applicable to penetrations with only one PCIV and a closed system inside primary containment. This Note is necessary since this Condition is written to specifically address those penetrations isolated in accordance with 10 CFR 50, Appendix A, GDC 57 (Ref. 2). GDC 57 allows those lines that enter primary containment but are neither part of the reactor coolant pressure boundary nor connected directly to the primary containment atmosphere to be isolated by means of one PCIV.

Condition B is further modified by a Note indicating that the condition is only applicable to excess-flow check valves that isolate instruments that provide signals to protection systems, since these valves are located in small-diameter lines and more time can be allowed for their repair.

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

In the event that one or more PCPVs 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 use 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 deactivated automatic valve,

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BASES (continued)

ACTIONS (continued)

closed manual valve, or blind flange. One of these Required Actions must be completed within 24 hours. The 24-hour Completion Time is reasonable considering that the PCPVs remain closed such that a gross breach of primary containment does not exist. For PCPVs that are isolated in accordance with Required Action C.2.1, SR 3.6.1.3.8 must be performed at least once per 92 days. This ensures that degradation of the resilient seals is detected and confirms that the leakage rate of the PCPVs does not increase during the time that the penetration is isolated. The normal Frequency of SR 3.6.1.3.8 is 184 days and is based on an NRC initiative (Generic Issue B-20) "Containment Leakage Due to Seal Deterioration" (Ref. 6). Since more reliance is being placed on a single valve while in this condition, it is prudent to perform the SR more often. Therefore, a periodic interval of once per 92 days is appropriate.

D.1

With one or more PCIVs inoperable in one or more penetration flow paths, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support PCIVs within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition D.

Required Action D.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of PCIVs have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition D of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

E.1

With one or more PCIVs inoperable in one or more penetration flow paths, AND one or more required support or supported

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BASES (continued)

ACTIONS (continued)

features, or both, inoperable associated with the other redundant penetration flow paths, the result is a loss of functional capability, and LCO 3.0.3 must be immediately entered. However, if the support or supported feature LCO, or both, take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

An example illustrating this situation would be when a support PCIV is declared inoperable and subsequently is isolated in a penetration flow path associated with a supported ESF system, then the other penetration flow paths associated with the redundant counterpart supported ESF systems and their support systems must be OPERABLE; otherwise, a loss of functional capability exists. A loss of functional capability in this case may place the operation of the plant outside the safety analyses. Therefore, immediate actions must be taken to bring the plant to a MODE outside the Applicability of the LCO for the PCIVs.

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if the Required Actions and associated Completion Times are not met in MODE 1, 2, or 3. This is done by placing the plant in at least MODE 3 within 12 hours and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

G.1, H.1, I.1, and I.2

The plant must be placed in a condition in which the LCO does not apply if the Required Actions and associated Completion Times are not met. If applicable, CORE ALTERATIONS and handling of irradiated fuel must be immediately 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

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BASES (continued)

ACTIONS (continued)

OPDRVs are suspended and valves are restored to OPERABLE status. If suspending an OPDRV would result in closing the residual heat removal-shutdown cooling isolation valves, the action of LCO [ ] will govern the operation of those valves and alternate solutions to compensate for the loss of shutdown cooling, if needed. [For this facility the valves or systems required to be OPERABLE as related to Conditions G, H, and I, and associated with actuation instrumentation required to be OPERABLE per LCO 3.3.6.1 are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

Each [18]-inch PCPV 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 PCPV. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to prevent offsite dose limits from exceeding 10 CFR 100 limits (Ref. 9) or some fraction, as established in the NRC staff-approved licensing basis. Therefore, these valves are required to be in sealed-closed position during MODES 1, 2, and 3. PCPVs 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. In this application, the term "sealed" has no connotation of leak tightness. The 31-day Frequency is a result of an NRC initiative, Generic Item B-24 (Ref. 7), related to PCPV using during plant operations.

SR 3.6.1.3.2

This SR ensures that the PCPVs are closed as required or, if open, open for an allowable reason. This SR has been modified by a Note indicating that these valves may be opened for inerting, de-inerting, pressure control, as low as reasonably achievable (ALARA) air quality considerations for personnel entry, and Surveillance tests that require the valve to be open. The [18]-inch purge valves are capable of closing in the environment following a LOCA. Therefore,

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

these valves are allowed to be open for limited periods of time. The 31-day Frequency is consistent with other PCIV requirements discussed under SR 3.6.1.3.3.

SR 3.6.1.3.3

This SR verifies that all primary containment isolation manual valves and blind flanges that are located outside primary containment and required to be closed during accident conditions are closed. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits.

The Inservice Inspection and Testing Program requires valve testing on a 92-day Frequency. 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 potentially being mispositioned are in the correct position. Since verification of valve position for valves outside of primary containment is relatively easy, the 31-day Frequency was chosen to provide added assurance that the valves are in the correct positions.

Several Notes have been added to this SR. The first Note allows valves and blind flanges located in high-radiation areas to be verified as closed 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 small. A second Note has been added that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. These administrative 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 valid primary containment isolation signal is indicated. A third Note has been included to clarify that valves that are open under administrative

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

controls are not required to meet the SR during the time that the valves are open. The provisions of LCO 3.0.4 apply.

SR 3.6.1.3.4

This SR verifies that all primary containment isolation manual valves and blind flanges that are located inside primary containment and required to be closed during accident conditions are closed. The SR helps to ensure that post-accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. 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 and if not performed more often than once per 92 days" is appropriate since these valves and flanges are operated under administrative control and the probability of their misalignment is low.

A Note has been added to this SR that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. The administrative 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 valid primary containment isolation signal is indicated. An additional Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open. The provisions of LCO 3.0.4 apply.

SR 3.6.1.3.5

The transversing incore probe (TIP) isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6

Demonstrating that the isolation time of each power-operated and automatic PCIV 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 are in accordance with the requirements of the Inservice Inspection and Testing Program, but the Frequency must not exceed 92 days. This SR has been modified by a Note indicating that MSIVs may be excluded from this SR since MSIV full-closure isolation time is demonstrated by SR 3.6.1.3.7.

SR 3.6.1.3.7

Demonstrating that the full-closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full-closure 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 that the calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is in accordance with the requirements of the Inservice Inspection and Testing Program but must not exceed 92 days.

SR 3.6.1.3.8

For PCPV with resilient seals, additional leakage-rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 8), is required to ensure OPERABILITY. [For this facility the individual purge valve leakage-rate limits are as follows:] 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 on Generic Issue B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 6).

Additionally, this SR must be performed within 92 days of opening the valve. The 92-day Frequency was chosen

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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.

A 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 PCPV leakage is properly accounted for in determining the overall primary containment leakage rate to verify primary containment OPERABILITY.

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 18-month Frequency was developed considering it is prudent that this Surveillance be performed only during a plant outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components.

Operating experience has shown that these components usually pass this SR when performed on 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 is OPERABLE by verifying that the valve reduces flow to $\leq$ 1 gph on a simulated line break. This SR provides assurance that the instrumentation line excess-flow check valves will perform so that predicted radiological consequences will not be exceeded during the postulated instrumentation-line break event evaluated in Reference 4. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown that

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

these components usually pass this SR when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.11

The TIP 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

The analyses in References 4 and 5 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ [11.5] scfh when tested at P_t [28.8] psig. The MSIV leakage rate must be demonstrated in accordance with the leakage-test requirements of 10 CFR 50, Appendix J (Ref. 8), as modified by approved exemptions, as described in the Primary Containment Leakage Rate Testing Program. The Frequency of this SR is in accordance with the requirements of the Inservice Inspection and Testing Program.

SR 3.6.1.3.13

Leakage through each hydrostatically tested line that penetrates primary containment is not to exceed 1 gpm when tested at [63.25] psig. Surveillance of these leakage rates provides assurance that the calculation assumptions of References 4 and 5 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-test requirements of 10 CFR 50, Appendix J, as modified by approved exemptions, as described in the Primary Containment Leakage Rate Testing Program.

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BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

   General Design Criterion 50, "Containment Design Basis";

   General Design Criterion 52, "Capability for Containment Leakage Rate Testing";

   General Design Criterion 53, "Provisions for Containment Inspection and Testing";

   General Design Criterion 54, "Piping Systems Penetrating Containment";

   General Design Criterion 56, "Primary Containment Isolation"; and

   General Design Criterion 57, "Closed System Isolation Valves."

3. [Unit Name] FSAR, Section [ ], "[Title]."

4. [Unit Name] FSAR, Section [ ], "[Title]."

5. [Unit Name] FSAR, Section [ ], "[Title]."

6. Generic Issue B-20, "Containment Leakage Due to Seal Deterioration."

7. Generic Issue B-24, "Containment Purge Valve Reliability."

8. Title 10, Code of Federal Regulations, Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

9. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND

The limit on drywell pressure is a reasonable upper bound based on plant operating experience. A positive internal pressure ensures that air does not leak into an inerted primary containment. The primary containment serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA), such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

Drywell pressure is a process variable that is monitored and controlled. The pressure limit is derived from the input conditions used in the primary containment functional analyses and the primary containment structure external pressure analysis. Should operation occur outside this limit, a loss of primary containment OPERABILITY may result in the event of a DBA. Loss of primary containment OPERABILITY could cause site-boundary doses to exceed values specified in the licensing basis.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated loss-of-coolant accidents (LOCAs) (Ref. 2). Among the inputs to the DBA is the initial containment internal pressure (Ref. 2). Analyses assume an initial drywell pressure of [0.75] psig. 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 [62] psig.

The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is [57.5] psig (Ref. 2).

Drywell pressure satisfies Criterion 2 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

In the event of a DBA, with an initial drywell pressure ≤ [0.75] psig, the resultant peak drywell accident pressure will be maintained below the drywell design pressure. As a result, primary containment OPERABILITY is ensured.

[For this facility, the following support systems are required to be OPERABLE to ensure drywell pressure channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the drywell pressure channel inoperable and their justification are as follows:]

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 to ensure primary containment OPERABILITY.

ACTIONS

A.1

With drywell pressure not within the limits 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 Required Actions of LCO 3.6.1.1, "Primary Containment," which requires that Primary Containment be restored to OPERABLE status within 1 hour.

In the event that the required drywell pressure channels are found inoperable, the drywell pressure is considered to be not within limits and Required Action A.1 applies.

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BASES (continued)

ACTIONS (continued)

B.1 and B.2

If drywell pressure cannot be restored to within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell pressure is within limits ensures that facility operation remains within the limits 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 and to assessing the proximity to the specified LCO pressure limits. 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. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

2. [Unit Name] FSAR, Section [ ], "[Title]."

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 equipment OPERABILITY, personnel access, and the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as a reasonable upper bound based on operating plant experience. The limitation on drywell temperature is used in the Reference 1 safety analyses. This LCO sets a maximum limit on initial drywell average air temperature.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the 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 [135]°F. 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 of [340]°F (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 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 that results in the blowdown of reactor steam to the drywell. The drywell temperature analysis considers main steam line breaks (MSLBs) occurring inside the drywell and having break areas 0.01 ft^2, 0.1 ft^2, and 0.5 ft^2. The maximum calculated drywell average temperature of [326]°F occurs for the 0.1 ft^2 break (Ref. 3). [For this facility, the temperature limit used to establish that the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

environmental qualification operating envelope for primary containment is [ ]°F].

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

LCO

In the event of a DBA, with an initial drywell average temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the primary containment design temperature. As a result, the ability of primary containment to perform its design function is ensured.

[For this facility, the following support systems are required OPERABLE to ensure drywell air temperature channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the drywell air temperature channels inoperable and their justification are as follows:]

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 air 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

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BASES (continued)

ACTIONS (continued)

minor problems or to prepare the plant for an orderly shutdown.

In the event that the required drywell air temperature channels are found inoperable, the drywell air temperature is considered to be not within limits and Required Action A.1 applies.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the drywell average air temperature cannot be restored within limits in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowable Completion Times are reasonable based on operating experience to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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 in the primary containment analysis. 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 considering operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES. 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. [Unit Name] FSAR, Section [ ], "[Title]."
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Suppression-Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression-chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 12 internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression-cha[illegible]r-to-drywell vacuum breakers prevent an excessive negative differential [illegible]ressure across the wetwell-drywell boundary. Each [illegible]er is a self-actuating valve, similar to a che[illegible]n can be remotely operated for testing [illegible]es.

A negative differential pressure across the drywell wall 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 reflood of a break in the event 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 spill of subcooled water out of a break result in more significant pressure transients and become 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, air in the drywell is purged into the suppression chamber 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 recirculation line break, 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 water leg in the Mark I vent system downcomer is controlled by the drywell-to-suppression-chamber differential pressure. If the drywell pressure is

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BASES (continued)

BACKGROUND (continued)

less than the suppression chamber pressure, there will be an increase in the vent water leg. This will result in an increase in the peak drywell pressure and will produce an increase in the water-clearing inertia in the event of a postulated LOCA. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the water leg in the vent system during normal operation.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the suppression-chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Internal (suppression chamber-to-drywell) and external (suppression-chamber-to-reactor building) vacuum breakers are provided as part of the primary containment to limit the negative pressure differential across the drywell and suppression chamber 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 [0.5] psid (Ref. 1). Additionally, 3 of the 12 internal vacuum breakers are assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst-case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that 9 of 12 vacuum breakers be operational are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The total cross-sectional area of the main vent system between the drywell and suppression chamber needed to fulfill this requirement has been established as a minimum of [51.5] times the total break area (Ref. 1). In turn, the vacuum relief capacity between the drywell and suppression chamber should be [1/16] of the total main vent cross-sectional area with the valves set to operate at [0.5] psid pressure differential. Design Basis Accident (DBA) analyses require the vacuum breakers to be closed initially and to remain closed and leak tight, with positive containment pressure, to ensure limits of 10 CFR 100 (Ref. 2), or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The suppression-chamber-to-drywell vacuum breakers satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Only 9 of the 12 vacuum breakers must be OPERABLE for opening. All suppression-chamber-to-drywell vacuum breakers, however, are required to be closed (except during testing or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression-chamber negative pressure differential 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.

[For this facility, an OPERABLE vacuum breaker constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure suppression-chamber-to-drywell vacuum breaker OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the suppression chamber-to-drywell vacuum breakers inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, the Drywell Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside the drywell could occur whenever this system is required to be OPERABLE due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3 to mitigate the effects of inadvertent actuation of the Drywell Spray System. Also, 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.

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BASES (continued)

APPLICABILITY (continued)

The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam 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. 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 suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5 to ensure primary containment OPERABILITY.

A Note has been added to provide clarification that for this LCO, all suppression-chamber-to-drywell vacuum breakers are treated as an entity with a single Completion Time.

ACTIONS

A.1

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. The 2-hour Completion Time is based on the time required to complete the alternate method of verifying that the vacuum breakers are closed, and the low probability of a DBA occurring during this period.

[For this facility the alternate method for verifying that the vacuum breakers are closed is as follows:]

With more than one required suppression-chamber-to-drywell vacuum breakers open, the plant is outside the safety analyses. Therefore, LCO 3.0.3 must be immediately entered.

B.1

With one of the required vacuum breakers inoperable for reasons other than Condition A (e.g., the vacuum breaker is not open, and may be stuck closed or not within its opening setpoint limit, such that it would not function as designed during an event that depressurized the drywell), the

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BASES (continued)

ACTIONS (continued)

remaining eight OPERABLE vacuum breakers are capable of providing the vacuum relief function. A Completion Time of 72 hours is allowed to restore vacuum breakers to OPERABLE status. The 72-hour Completion Time takes into account the redundant capability afforded by the remaining breakers, reasonable time for the repairs, and the low probability of an event occurring during this period requiring the vacuum breakers to function.

With more than one required suppression chamber-to-drywell vacuum breaker inoperable for reasons other than Condition A, the plant is outside the safety analyses. Therefore, LCO 3.0.3 must be immediately entered.

C.1 and C.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable suppression-chamber-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status in the associated Completion Time. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Each vacuum breaker is verified as closed (except when being tested in accordance with SR 3.6.1.6.2) to ensure that this potential, large bypass leakage path is not present. This SR is performed by observing the vacuum breaker position indication, or by verifying that the vacuum breakers are closed when a differential pressure of [0.5] psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The 14-day Frequency is based on engineering judgment and is considered adequate in view of other indications of vacuum breaker status available to operations personnel and has been shown to be acceptable through operating experience.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 31-day Frequency of this SR was developed based on Inservice Inspection and Testing Program requirements to perform valve testing at least once every 92 days. A 31-day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE.

SR 3.6.1.6.3

Demonstration of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full-open differential pressure of [0.5] psid is valid. The 18-month Frequency was developed considering it is prudent that this SR be performed only during a plant outage. For this facility, the 18-month Frequency has been shown to be acceptable through operating experience and is further justified because of other SRs performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Reactor-Building-to-Suppression-Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor-building-to-suppression-chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor-building-to-suppression-chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor-building-to-suppression-chamber) vacuum relief provisions consists of two vacuum breakers (a vacuum breaker and an air-operated butterfly valve), located in series in each of two lines from the reactor building to the suppression chamber airspace. The butterfly valve is actuated by differential pressure. The vacuum breaker is self-actuating and can be remotely operated for testing purposes. The two vacuum breakers in series must be closed and leak tight to maintain a leak-tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. reactor-building-to-suppression-chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor-building-to-suppression-chamber) vacuum breakers.

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary

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BASES (continued)

BACKGROUND (continued)

containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the reactor-building-to-suppression-chamber vacuum breakers are presented in Reference 1 as part of the accident response of the containment systems. Internal (suppression chamber-to-drywell) and external (reactor-building-to-suppression-chamber) vacuum breakers are provided as part of the primary containment to limit the negative pressure differential across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breakers to be closed initially and to be fully open at [0.5] psid (Ref. 1). Additionally, of the two reactor-building-to-suppression-chamber vacuum breakers, one is assumed to fail in a closed position to satisfy the single active failure criterion. Design Basis Accident (DBA) analyses require the vacuum breakers to be closed initially and to remain closed and leak tight, with positive primary containment pressure, to ensure that site-boundary radiation doses will not exceed licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

Five cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

a. A small-break loss-of-coolant accident (LOCA) followed by actuation of both primary containment spray loops;

b. Inadvertent actuation of one primary containment spray loop during normal operation;

c. Inadvertent actuation of both primary containment spray loops during normal operation;

d. A postulated DBA assuming Emergency Core Cooling System (ECCS) runout flow with a condensation effectiveness of 50%; and

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

e. A postulated DBA assuming ECCS runout flow with a condensation effectiveness of 100%.

The results of these five cases show that the external vacuum breakers, with an opening setpoint of [0.5] psid, are capable of maintaining the differential pressure to within design limits.

The reactor-building-to-suppression-chamber vacuum breakers satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

All reactor-building-to-suppression-chamber vacuum breakers are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that the two vacuum breakers (vacuum breaker and air-operated butterfly valve) in each of the two lines from the reactor building to the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, both vacuum breakers in each line will open to relieve a negative pressure in the suppression chamber.

[For this facility an OPERABLE reactor-building-to-suppression-chamber vacuum breaker consists of the following:]

[For this facility, the following support systems are required OPERABLE to ensure reactor-building-to-suppression-chamber vacuum breaker OPERABILITY:]

In addition, a reactor-building-to-suppression-chamber vacuum breaker is considered OPERABLE when it satisfies all SRs.

[For this facility, those required support systems which upon their failure do not require declaring the reactor-building-to-suppression-chamber vacuum breakers inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 1, 2, and 3, the Drywell

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BASES (continued)

APPLICABILITY (continued)

Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside primary containment could occur whenever this system is required to be OPERABLE due to inadvertent actuation of this system. Therefore, the vacuum breakers are required to be OPERABLE in MODES 1, 2, and 3 to mitigate the effects of inadvertent actuation of the drywell Spray System.

Also 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, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam 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.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitation in these MODES. Therefore, maintaining reactor-building-to-suppression-chamber vacuum breakers OPERABLE is not required in MODE 4 or 5 to ensure primary containment OPERABILITY.

A Note has been added to provide clarification that all reactor-building-to-suppression-chamber vacuum breakers are treated as an entity for this LCO, with a single Completion Time.

ACTIONS

A.1 and A.2

With one or more vacuum breakers open in one or more lines, the leak-tight primary containment boundary may be threatened. Therefore, it must be confirmed that at least one vacuum breaker in each affected line is closed. This Required Action must be completed within 1 hour, consistent with the Required Actions of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour. Failure to verify a closed vacuum breaker would imply that a breach in primary containment exists. The inoperable vacuum breakers must be restored to OPERABLE

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BASES (continued)

ACTIONS (continued)

status within 72 hours. The 72-hour Completion Time is consistent with requirements for inoperable suppression-chamber-to-drywell vacuum breakers in LCO 3.6.1.6. The 72-hour Completion Time takes into account the redundancy capability afforded by the remaining breakers, the fact that the OPERABLE breaker in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breakers to be OPERABLE during this period.

B.1 and B.2

With one or more vacuum breakers in one or more lines inoperable (incapable of opening) but known to be closed, the leak-tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened, however, if both vacuum breakers in at least one vacuum breaker penetration are not OPERABLE. Therefore, an OPERABLE vacuum breaker penetration must be verified within 1 hour to ensure that the vacuum-relief functional capability is maintained. This 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. The inoperable vacuum breakers must be restored to OPERABLE status within 72 hours, consistent with the Completion Time for Condition A and the fact that the leak-tight primary containment boundary is being maintained.

C.1 and C.2

If the vacuum breakers cannot be closed or restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified to be closed (except when being tested in accordance with SR 3.6.1.7.2) to ensure that a potential breach in the primary containment boundary is not present. This SR is performed by observing local or control room indications of vacuum breaker position or by verifying that vacuum breakers are closed when a differential pressure of [0.5] psid is maintained between the reactor building and suppression chamber. The 14-day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The 31-day Frequency of this SR was developed based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once every 92 days. A 31-day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE.

SR 3.6.1.7.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full-open differential pressure of [0.5] psid is valid. The 18-month Frequency was develo... considering it is prudent that this Surveillance be performed only during a plant outage. For this facility, the 18-month Frequency has been shown to be acceptable through operating experience and is further justified because of other SRs performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Low-Low Set (LLS) Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The S/RVs can actuate in either the relief mode, safety mode, the Automatic Depressurization System (ADS) mode, or the LLS relief mode. In the LLS relief mode (or power-actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the pilot valve. As in the safety mode, opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. The main valve can stay open with valve inlet steam pressure as low as [50] psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the pilot valves. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.

Four of the S/RVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and stay open longer, such that reopening more than one S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short-duration S/RV cycles with valve actuation at the relief setpoint.

Each S/RV discharges steam through a discharge line and quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load.

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of one S/RV operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of S/RVs (following the initial opening), and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Accidents (DBAs). Furthermore, the LLS function justifies the primary containment analysis assumption that simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though four LLS S/RVs are specified, all four LLS S/RVs do not operate in any DBA analysis.

LLS S/RVs satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Four LLS S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analyses (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS S/RVs to function for controlling the opening/closing of the S/RVs.

[For this facility, an OPERABLE LLS S/RV constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure LLS S/RVs OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the LLS S/RVs inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of S/RVs. 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 LLS S/RVs OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one of the four LLS S/RVs inoperable, the remaining OPERABLE LLS S/RVs are adequate to perform the designed function. The 14-day Completion Time takes into account the

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BASES (continued)

ACTIONS (continued)

redundant capability afforded by the remaining LLS S/RVs and the low probability of an event in which the remaining LLS S/RV capability would be inadequate.

B.1 and B.2

If more than one LLS S/RV is inoperable, or if the inoperable LLS S/RV cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.8.1

A manual actuation of each LLS S/RV is performed to verify that the valve and solenoids are functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve or by a change in the measured steam flow or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. The 18-month Frequency was based on the S/RV tests required by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI (Ref. 2), and the importance of these valves during DBAs. It was also considered prudent that the Surveillance not be performed with the reactor at full power. This is due to the potential for an unplanned plant transient if the SR is performed with the reactor at full power. 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Since steam pressure is required to perform the SR, however, and steam may not be available during a plant outage, the SR should be performed during the shutdown prior to or the startup following a plant outage. Plant startup is allowed prior to performing the test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 2 prior to valve installation. After required reactor steam dome pressure is reached, 12 hours are allowed to prepare for and perform the test once only. Adequate pressure at which this test is to be performed is [920] psig (the pressure recommended by the valve manufacturer).

A Note is included in the SR to indicate that the provisions of SR 3.0.4 do not apply.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.9 Main Steam Line Isolation Valve (MSIV) Leakage Control System (LCS)

BASES

BACKGROUND

The MSIV LCS supplements the isolation function of the MSIVs by processing the fission products that could leak through the closed MSIVs after a Design Basis Accident (DBA) to ensure that the limits of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis are not exceeded.

The MSIV LCS consists of two independent subsystems: an inboard subsystem, connected between the inboard and outboard MSIVs, and an outboard subsystem, connected immediately downstream of the outboard MSIVs. Two independent subsystems provide diverse backup to the MSIV isolation function to mitigate potential leakage. (Note that fission products could not be released unless both an inboard and an outboard MSIV leaked in conjunction with a steam pipe failure that allowed a release to the environment.) Each subsystem comprises three blowers (one blower for the inboard subsystem and two blowers for the outboard subsystem). Four inboard subsystem electric heaters are provided to boil off any condensate prior to the gas mixture passing through the flow limiter.

Each subsystem operates in two process modes: depressurization and bleed-off. During depressurization, the effluent is discharged to the Standby Gas Treatment System. The depressurization process reduces the steam line pressure to within the operating capability of equipment used for the bleed-off mode. During bleed-off (long-term leakage control), the leakage through the closed MSIVs is collected and processed by the MSIV LCS.

Subsequent to a DBA, system operation starts upon manual actuation. Once system operation is established, it continues to operate unless terminated by control room operators or automatically stopped as dictated by process control.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 2 defines the DBA and requirements for the MSIV LCS. Reference 2 also evaluates plant response without an MSIV LCS for a DBA with an additional seismic-induced failure of non-Category I steam piping, coincident with induced leakage of the MSIVs in excess of the allowable limits. This leakage, combined with site meteorological data, resulted in a calculated dose that exceeded the 10 CFR 100 requirements. The operation of the MSIV LCS prevents a release of untreated leakage for this type of event, such that the offsite dose is within 10 CFR 100 SAFETY ANALYSES requirements or within the NRC staff-approved licensing basis.

The MSIV LCS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two independent and manually initiated MSIV LCS subsystems must be OPERABLE to satisfy the single-failure criterion as delineated in Reference 2 and to ensure that total site radiological limits are not exceeded. A typical description of the requirement for MSIV LCS OPERABILITY is provided in the Background section.

[For this facility, an OPERABLE MSIV LCS constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure MSIV LCS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the MSIV LCS inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause primary containment isolation. 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 MSIV LCS OPERABLE is not required in MODE 4 or 5 to ensure primary containment is leak tight.

(continued)

BASES (continued)

ACTIONS

A.1

With one MSIV LCS subsystem inoperable, the inoperable MSIV LCS must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on the redundant capability afforded by the remaining OPERABLE MSIV LCS subsystem and the low probability of the event specified in Reference 2.

Concurrent failure of two MSIV LCS would result in the loss of functional capability. Therefore LCO 3.0.3 must be entered immediately.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the MSIV LCS subsystems cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant 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, related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1

Each MSIV LCS blower is operated for at least 15 minutes to demonstrate OPERABILITY. The 31-day Frequency was developed considering the known reliability of the LCS blower and controls, the two-subsystem redundancy, and the low probability of a significant degradation of the MSIV LCS subsystems occurring between Surveillances, and has been shown to be acceptable through operating experience.

SR 3.6.1.9.2

The electrical continuity of each inboard heater is demonstrated by a resistance check, by verifying that the rate of temperature rise meets specifications, or by verifying that the current or wattage draw meets specifications. The 31-day Frequency is based on operating experience that has shown that these components usually pass this SR when performed at this Frequency.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.9.3

A system functional test is performed to ensure that the MSIV LCS will operate through its operating sequence, that is, that the automatic positioning of the valves is correct, that the blowers start and develop the required flow rate and the necessary vacuum, and that the upstream heaters meet current or wattage draw requirements (if not used to demonstrate electrical continuity in SR 3.6.1.9.2). The Surveillance also includes verification of the operation of each interlock and timer. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. For this facility, the 18-month Frequency has been shown to be acceptable through operating experience and is further justified because of other Surveillances performed at shorter Frequencies that convey the proper functional status of each MSIV LCS subsystem.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

2. Regulatory Guide 1.96, "Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants," Revision 1, June 1976.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppress ɔn Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal-shaped steel 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 energy released during a reactor blowdown from safety/relief valve (S/RV) discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the downcomer 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 maximum allowable pressure for DBAs ([62] psig). The suppression pool must also condense steam from steam exhaust lines in the turbine-driven systems (i.e., the High Pressure Coolant Injection System and 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 170°F, based on the Bodega Bay and Humboldt Bay Tests;

b. primary Containment Peak Pressure and Temperature — maximum allowable pressure is [62] psig and design temperature is [340]°F (Ref. 1);

c. Condensation Oscillation Loads — maximum allowable initial temperature is [110]°F; and

d. Chugging Loads — these only occur below [135]°F; therefore there is no initial temperature limit because of chugging.

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BASES (continued)

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 (Ref. 1 for LOCAs, and Ref. 2 for the pool temperature analyses required by Ref. 3). An initial pool temperature of [95]°F is assumed for the Reference 1 and Reference 2 analyses. Reactor shutdown at a pool temperature of [110]°F and vessel depressurization at a pool temperature of [120]°F are assumed for the Reference 2 analyses. The limit of [105]°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed not to initiate during plant testing.

The suppression pool is also designed to quench the energy from S/RV discharges. Thus, the safety analyses related to the suppression pool must consider all accident scenarios that involve SR/V actuations. The limit for the suppression pool average temperature is set low enough to preclude local boiling due to SR/V discharge from the [plant-specific S/RV discharge pressure suppression device].

The suppression pool average temperature limit is also set low enough to preclude pump cavitation by plant water systems that use the suppression pool as a source of water.

Suppression pool average temperature satisfies Criteria 2 and 3 of the NRC Interim Policy Statement.

LCO

A limitation on the suppression pool average temperature is required to ensure 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 ≤ [95]°F when THERMAL POWER ≥ 1% RATED THERMAL POWER (RTP) and when not testing equipment that discharges steam to the suppression pool. This requirement ensures that licensing bases initial conditions are met.

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BASES (continued)

LCO (continued)

b. Average temperature $\leq$ [105]°F when THERMAL POWER $\geq$ 1% RTP and when testing equipment that discharges steam to the suppression pool. This requirement ensures that the plant has testing flexibility and was selected to provide margin below the [110]°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to $\leq$ [95]°F within 24 hours per Required Action A.2. Therefore, the time period that the temperature is above [95]°F is short enough not to cause a significant increase in plant risk.

c. Average temperature $\leq$ [110]°F when THERMAL POWER $\leq$ 1% RTP. This requirement ensures that the plant will be shut down upon exceeding [110]°F. 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.

Note that [25/40] divisions of full scale on intermediate range monitor (IRM) Range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP. At this power level, heat input is approximately equal to normal system heat losses.

[For this facility, an OPERABLE suppression pool average temperature instrumentation channel is established in LCO [ ] or SR [ ] and constitutes the following:]

[For this facility, an OPERABLE IRM is established in LCO [ ] or SR [ ] and constitutes the following:]

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 MODES 4 or 5 to ensure primary containment OPERABILITY. A Note has been added to provide clarification that all suppression pool average temperature conditions are treated as an entity for this LCO, with a single Completion Time.

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BASES (continued)

ACTIONS

A.1 and A.2

If the suppression pool average temperature is above the specified limit when not performing testing that adds heat to the suppression pool above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1, 3, and 4 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 temperature to be restored below the limit. Additionally, when pool temperature is above [95]°F, increased monitoring of the pool temperature is required to ensure that it remains ≤ [110]°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly when not performing testing that adds heat to the pool. 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.

B.1

The plant must be placed in a MODE in which the LCO does not apply if suppression pool average temperature cannot be restored to within limits in the associated Completion Time.

This is done by reducing power to below 1% RTP within 12 hours. The 12-hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

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

Suppression pool average temperature ≤ [105]°F during testing that adds heat to the suppression pool is allowed by the LCO when above 1% RTP. If temperature exceeds [105]°F, all testing must be immediately suspended to preserve the heat absorption capability of the pool. The basis for the Completion Times to verify pool temperature is ≤ [110]°F and

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BASES (continued)

ACTIONS (continued)

to restore it to ≤ [95]°F is the same as that provided for Required Actions A.1 and A.2 above.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the suppression pool average temperature cannot be restored to within limits in the associated Completion Time. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

E.1 and E.2

Suppression pool average temperature ≥ [110]°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor MODE switch in the shutdown position. Additionally, when pool temperature is above [110]°F, increased monitoring of pool temperature is required to ensure that it remains below [120]°F. The once per 30 minutes Completion Time is adequate based on operating experience. 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. In addition, SR 3.6.2.1.1 verifies suppression pool average temperature is within applicable limits every 5 minutes when tests that add heat to the suppression pool are being performed.

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if suppression pool average temperature cannot be maintained below [120°]F. This is done by reducing reactor pressure to below [200] psig within 12 hours and placing the plant in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems. Continued heat addition to the suppression pool with pool temperature above [120°]F could result in

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BASES (continued)

ACTIONS (continued)

exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was above [120]°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

G.1, G.2, and G.3

With fewer than the required number of OPERABLE suppression pool average temperature channels established in LCO [ ] or in SR [ ] OR with fewer than the required number of OPERABLE IRM or THERMAL POWER channels established in LCO [ ] or in SR [ ], there is no confidence in the comparisons within the limits nor in the adequacy of the pool temperature with respect to RTP (respectively). Therefore, all testing that adds heat to the suppression pool must be immediately suspended, and either all required channels are restored to OPERABLE status with 8 hours or the plant is placed in MODE 4 within 44 hours. The Completion Time of 8 hours takes into consideration reasonable time for repairs and the low probability of an event occurring during this interval (after all testing has been suspended) that will add heat to the suppression pool. An additional 8 hours has been added to the normal Completion Time of 36 hours to reach MODE 4 in order to ensure that in the event the channels cannot be restored to OPERABLE status within 8 hours, there is sufficient time remaining to reduce power from full power in an orderly manner and without challenging plant systems.

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 OPERABLE suppression pool water temperature channels. At least one Suppression pool water temperature instrumentation channel in each sector of the suppression pool must be OPERABLE. The required number of OPERABLE channels is established in LCO [ ] or SR [ ]. The 24-hour Frequency has been shown, through 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

5-minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool and has been shown to be acceptable through operating experience. This 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.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Containment Systems]."
2. [Unit Name, suppression pool temperature response Document].
3. NUREG-0783, "Suppression Pool Temperature Limits for BWR Containments," November 1981.
4. [Unit Name, Mark I Containment Program, "Plant Unique Load Definition"].

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression chamber is a toroidal-shaped, steel 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 downcomer 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 maximum allowable pressure for DBAs ([62] psig). The suppression pool must also condense steam from the steam exhaust lines in the turbine-driven systems (i.e., High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling System (RCIC) System) and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between [87,300] ft^3 at the low-water-level alarm of [12'2"] and [90,550] ft^3 at the high-water-level alarm of [12'6"].

If the suppression pool water level is too low, insufficient water would be available to adequately condense the steam from the S/RV quenchers, main vents, or HPCI and 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 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 pool swell 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.

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BASES (continued)

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 Criterion 2 of the NRC Interim Policy Statement.

LCO

A limit that suppression pool water level between [12'2"] and [12'6"] 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.

[For this facility an OPERABLE suppression pool water level channel constitutes the following:]

[For this facility the following support systems are required to be OPERABLE to ensure suppression pool water level OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the suppression pool water level inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, a DBA would 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 to ensure primary containment OPERABILITY.

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BASES (continued)

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 main vents are covered, HPCI and RCIC turbine exhausts are covered, and S/RV quenchers are covered. If 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 containment sprays are OPERABLE. Therefore, continued operation for a limited time is allowed. The 2-hour Completion Time is sufficient to restore suppression pool 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.

In the event that the required suppression pool water level channels are found inoperable, the suppression pool water level is not considered to be within limits and Required Action A.1 applies.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if suppression pool water level cannot be restored to within limits in the associated Completion Time. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power 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 suppression pool water level variations and water-level instrument drift during the applicable MODES and to assessing the proximity to the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	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.
REFERENCES	1. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling System

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 two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains two pumps and one heat exchanger, which are manually initiated and independently controlled. The two 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. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink.

The heat-removal capability of one RHR pump in one subsystem 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 valve (S/RV). S/RV leakage and high-pressure core injection and reactor core isolation cooling 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

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

to demonstrate that the heat-removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The time history for suppression pool temperature is calculated to demonstrate that the maximum temperature remains below the design limit.

RHR suppression pool cooling satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

In the event of a DBA, of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling 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 suppression pool cooling subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

In addition each RHR suppression pool cooling subsystem must satisfy all the performance and physical arrangement SRs in order to be considered OPERABLE.

[For this facility the following support systems are required to be OPERABLE to ensure RHR suppression pool cooling subsystem OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the RHR suppression pool cooling subsystems inoperable and their justification are as follows:]

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

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BASES (continued)

APPLICABILITY (continued)

MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, RHR suppression pool cooling is not required to be OPERABLE in MODES 4 or 5.

ACTIONS

A.1

With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time was chosen in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

Concurrent failure of two RHR suppression pool cooling subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable RHR suppression pool cooling subsystems cannot be restored to OPERABLE status in the associated Completion Times. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power-operated, and automatic valves, excluding check 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 they were verified to be

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

in the correct position prior to being secured. A valve is also allowed to be in the non-accident position provided it can be aligned to its accident condition. This is acceptable since the RHR suppression pool cooling mode is manually initiated. The 31-day Frequency of this SR was developed based on the Inservice Inspection and Testing Program requirements to perform valve testing at least once per 92 days. 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 potentially being mispositioned, are in the correct position.

SR 3.6.2.3.2

Demonstrating at least once per 92 days that each RHR pump develops a flow rate > [7700] gpm while operating in the suppression pool cooling mode with flow through the heat exchanger 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. The Frequency of this SR is in accordance with the Inservice Inspection and Testing Program, but the Frequency must not exceed 92 days.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray System

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Spray System removes heat from the suppression chamber airspace. The suppression pool is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel (RPV) through safety/relief valves (S/RVs). The heat addition to the pool results in increased steam in the suppression chamber, which increases primary containment pressure. Steam blowdown from a DBA can also bypass the suppression pool and end up in the suppression chamber airspace. Some means must be provided to remove heat from the suppression chamber so that the pressure and temperature inside the primary containment remain within analyzed design limits. This function is provided by two redundant RHR suppression pool spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR suppression pool spray subsystems contains two pumps and one heat exchanger, which are manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool spray spargers. The spargers only accommodate a small portion of the total RHR pump flow; the remainder of the flow returns to the suppression pool through the pool-cooling return line. Thus, both pool cooling and pool spray functions are performed when the pool spray system is initiated. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink. Either RHR suppression pool spray subsystem is sufficient to condense the steam from small bypass leaks from the drywell to the suppression chamber airspace during the postulated DBA.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large- and small-break loss-of-coolant accidents (LOCAs). The intent of the analyses is to demonstrate that the pressure-reduction capacity of the RHR Suppression Pool Spray System is adequate to maintain the primary containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit.

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

LCO

In the event of a DBA, a minimum of one RHR suppression pool 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 suppression pool 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 suppression pool spray subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

In addition, each RHR suppression pool spray must satisfy all SRs in order to be considered OPERABLE.

[For this facility, the following support systems are required OPERABLE to ensure RHR suppression pool spray OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the RHR suppression pool spray inoperable and their justification are as follows:]

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause 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, maintaining RHR suppression pool spray subsystems OPERABLE is not required in MODES 4 or 5 to ensure primary containment OPERABILITY.

ACTIONS

A.1

With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7-day Completion Time was chosen in light of the redundant RHR suppression pool spray capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

Concurrent failure of two RHR suppression pool spray subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable RHR suppression pool spray subsystems cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the RHR suppression pool spray mode flow path 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 they were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the non-accident position provided it can be aligned to its accident position. This is acceptable since the RHR suppression pool cooling mode is manually initiated. The 31-day Frequency of this SR was developed based on the Inservice and Testing Program to perform valve testing at least once per 92 days. 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.

SR 3.6.2.4.2

Demonstrating at least once per 92 days that each RHR pump develops a flow rate > [7700] gpm while operating in the suppression pool spray mode with flow through the heat exchanger 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. The Frequency of this SR is in accordance with the Inservice Inspection and Testing Program, but the Frequency must not exceed 92 days.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.5 Drywell-to-Suppression-Chamber Differential Pressure

BASES

BACKGROUND

The toroidal-shaped suppression chamber, which contains the suppression pool, is connected to the drywell (part of the primary containment) by [eight] main vent pipes. The main vent pipes exhaust into a continuous vent header, from which [96] downcomer pipes extend into the suppression pool. The pipe exit is [4] feet below the minimum suppression pool water level required by LCO 3.6.2.2. During a loss-of-coolant accident (LOCA), the increasing drywell pressure will force the water leg in the downcomer pipes into the suppression pool at substantial velocities as the "blowdown" phase of the event begins. The length of the water leg has a significant effect on the resultant primary containment pressures and loads.

APPLICABLE SAFETY ANALYSES

The purpose of maintaining the drywell at a slightly higher pressure with respect to the suppression chamber is to minimize the drywell pressure increase necessary to clear the downcomer pipes to commence condensation of steam in the suppression pool and to minimize the mass of the accelerated water leg. This reduces the hydrodynamic loads on the torus during the LOCA blowdown. The required differential pressure results in a downcomer water leg of [3.06 to 3.58] feet.

Initial drywell-to-suppression-chamber differential pressure affects both the dynamic pool loads on the suppression chamber and the peak drywell pressure during downcomer pipe clearing during a Design Basis Accident (DBA) LOCA. Drywell-to-suppression-chamber differential pressure must be maintained within the specified limits so that the safety analysis remains valid.

Drywell-to-suppression-chamber differential pressure satisfies Criterion 2 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

A drywell-to-suppression-chamber differential pressure limit of [1.5] psid is required to ensure that the containment conditions assumed in the safety analyses are met. A drywell-to-suppression-chamber differential pressure of < [1.5] psid corresponds to a downcomer water leg of > [3.58] feet. Failure to maintain the required differential pressure could result in excessive forces on the suppression chamber and possible loss of primary containment OPERABILITY due to higher water-clearing loads from downcomer vents and higher pressure buildup in the drywell.

[For this facility the following support systems are required OPERABLE to ensure drywell-to-suppression-chamber differential pressure:]

[For this facility, those required support systems which upon their failure do not require declaring the drywell-to-suppression chamber differential pressure inoperable and their justification are as follows:]

APPLICABILITY

Drywell-to-suppression-chamber differential pressure can be controlled only when the primary containment is inert. The primary containment must be inert in MODE 1, since this is the condition with the highest probability for an event that could produce hydrogen. It is also the condition with the highest probability of an event that could impose large loads on the primary containment.

Inerting primary containment is an operational problem because it prevents primary containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and is de-inerted as soon as possible in the plant shutdown. As long as reactor power is below [15%] RATED THERMAL POWER (RTP), the probability of an event that generates hydrogen or excessive loads on primary containment occurring within the first [24] hours of a startup or within the last [24] hours before a shutdown is low enough that these "windows," with the primary containment not inerted, are also justified. The [24]-hour Completion Time is a reasonable amount time to allow plant personnel to perform inerting or de-inerting.

(continued)

BASES (continued)

ACTIONS

A.1

If drywell-to-suppression-chamber differential pressure is not within the limit, the conditions assumed in the safety analyses are not met and the differential pressure must be restored to within the limit in 8 hours. The 8-hour Completion Time provides sufficient time to restore differential pressure to within limits or to prepare the plant for an orderly reduction of power. Also, it takes into account the low probability of an event that would create excessive suppression chamber loads occurring during this time period.

In the event that the required drywell-to-suppression-chamber differential pressure channels are found inoperable, the drywell-to-suppression-chamber differential pressure is considered to be not within limits and Required Action A.1 applies.

B.1

The plant must be placed in a MODE in which the LCO does not apply if the differential pressure cannot be restored to within limits in the associated Completion Time. This is done by reducing power to ≤ 15% RTP within 12 hours. The 12-hour Completion Time is reasonable, based on operating experience related to the amount of time required to reduce reactor power from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.5.1

The drywell-to-suppression-chamber differential pressure is regularly monitored to ensure that the required limits are satisfied. The 12-hour Frequency of this SR was developed considering operating experience relative to differential pressure variations and pressure instrument drift during applicable MODEs and assessing the proximity to the specified LCO differential pressure limit. 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 pressure condition.

REFERENCES

None

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiner System (PCHRS)—MODES 1 & 2

BASES

BACKGROUND

The PCHRS, supports primary containment OPERABILITY in post-accident environments by eliminating the potential breach of primary containment due to a hydrogen-oxygen reaction.

Per 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 PCHRS is required to reduce the hydrogen concentration the primary containment following a loss-of-coolant Accident (LOCA). The PCHRS accomplishes this by recombining hydrogen and oxygen to form water vapor. The vapor remains in the primary containment, thus eliminating any discharge to the environment.

The PCHRS functions to maintain the hydrogen gas concentration within the containment at or below the flammability limit of 4.1 volume percent (v/o) following a postulated LOCA. It is fully redundant and consists of two 100%-capacity subsystems. Each PCHRS subsystem 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 PCHRS will be manually initiated from the main control room when the hydrogen gas concentration in the primary containment reaches [3.3] v/o. When the primary containment is inerted (oxygen concentration < 4 v/o), the PCHRS will only function until the oxygen is used up (2 v/o hydrogen combines with 1 v/o oxygen). The process-gas circulating through the heater, reaction chamber, and the cooler is automatically regulated to [150] scfm by the use of an orifice plate installed in the cooler. The process gas is heated to [1200]°F. 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 suppression chamber. 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.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCHRS ensures primary containment OPERABILITY by providing the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.1 v/o following a Design Basis Accident (DBA). This control would prevent a primary containment-wide hydrogen burn, thus ensuring primary containment OPERABILITY and minimizing challenges to the OPERABILITY of safety-related equipment located in primary containment. 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;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS); or

c. Hydrogen in the RCS at the time of the LOCA, that is, hydrogen dissolved in the reactor coolant for the control of austenitic stainless-steel intergranular stress corrosion cracking.

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. The assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

The PCHRS is designed so that, with the calculated hydrogen generation rates discussed above, a single PCHRS subsystem is capable of limiting the peak hydrogen concentration in primary containment to < 4.1 v/o (Ref. 4).

The PCHRS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two PCHRS subsystems must be OPERABLE with power from two independent, safety-related power supplies and cooling from two independent RHR subsystems. This assures the operation

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BASES (continued)

LCO (continued)

of at least one PCHRS subsystem in the event of a worst-case single active failure.

[For this facility, an OPERABLE PCHRS subsystem consists of the following:]

Operation with at least one PCHRS subsystem ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit. Unavailability of both PCHRS subsystems might lead to the generation of a sufficient amount of hydrogen (the flammability limit exceeded) that could react with oxygen following the accident. The reaction could take place fast enough to lead to high temperatures and overpressurization of primary containment and, as a result, breach primary containment or cause primary containment leakage rates above those assumed in the safety analyses. Damage to safety-related equipment located in primary containment could also occur.

[For this facility, the following support systems are required to be OPERABLE to ensure PCHRS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the PCHRS inoperable and their justification are as follows:]

APPLICABILITY

The purpose of requiring OPERABILITY in MODES 1 and 2 for the PCHRS subsystems is to ensure their availability after the safety injection and scram actuated on a LOCA initiation. In the post-accident LOCA environment, the two PCHRS subsystems are required to control the hydrogen concentration within primary containment below its flammability limit of 4.1 v/o following a LOCA, assuming a worst-case single failure. This ensures primary containment OPERABILITY and prevents damage to safety-related equipment and instruments located within primary containment.

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 these MODES, the probability of an accident requiring the PCHRS is low. Therefore, the PCHRS is not required in MODE 3.

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BASES (continued)

APPLICABILITY (continued)

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 PCHRS is not required in these MODES to ensure primary containment OPERABILITY.

ACTIONS

A.1

With one PCHRS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. 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 length of time after the event that operator action would be required to prevent this limit from being exceeded, and the low probability of failures of the OPERABLE PCHRS subsystem.

Concurrent failure of two PCHRS subsystems is considered a low-probability event. If such a double failure did occur, it would be indicative of poor PCHRS reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

If the inoperable PCHRS subsystem cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours. The 12 hours allotted to reach MODE 3 is a reasonable time, based on operating experience related to the amount of time required to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each PCHR subsystem ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

minimum heater sheath temperature increases to ≥ [1200]°F in ≤ [1.5] hours, and that it is maintained between [1150]°F and [1300]°F for at least [4] hours thereafter to check ability of the recombiner to function properly (and to ensure that significant heater elements are not burned out). The 18-month Frequency for this SR was developed considering such factors as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of a PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [Standby Gas Treatment System (SGTS)]; and

c. Since the PCHRS is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to OPERABLE status or activate an alternative.

SR 3.6.3.1.2

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 only to 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 abnormal conditions that could cause such failures. The 18-month Frequency for this SR was developed considering such factors as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of a PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [SGTS]; and

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

c. Since the PCHRS is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to OPERABLE status or activate an alternative.

SR 3.6.3.1.3

This SR performs 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.

The 18-month Frequency for this SR was developed considering such factors as the following:

a. The incidence of PCHRS failing the SR in the past is low;

b. Even when failure of a PCHRS subsystem has been detected, there has been, in all instances, a backup available either from the other PCHRS subsystem or from a diverse system [SGTS]; and

c. Since the PCHRS is manually started many hours after a LOCA occurs, there is time available to either restore a PCHRS subsystem to OPERABLE status or activate an alternative.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Power Reactors."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup."

3. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident, U.S. Nuclear Regulatory Commission."

4. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Hydrogen Mixing System (HMS)—MODES 1 & 2

BASES

BACKGROUND

The primary containment HMS supports primary containment OPERABILITY in post-accident environments by reducing the potential breach of containment due to a hydrogen-oxygen reaction. The HMS ensures primary containment OPERABILITY by providing a uniformly mixed post-accident primary containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration. Primary containment OPERABILITY limits leakage of fission-product radioactivity from primary containment to the environment.

The post-accident primary containment HMS is an ENGINEERED SAFETY FEATURE and is designed to withstand a loss-of-coolant accident (LOCA) without loss of function. The system has two independent subsystems consisting of fans, fan coil units, motors, controls, and ducting. Each subsystem is sized to circulate [500] cfm. The primary containment HMS employs both forced circulation and natural circulation to assure the proper mixing of hydrogen in primary containment. The recirculation fans provide the forced circulation to mix hydrogen while the fan coils provide the natural circulation by increasing the density through the cooling of the hot gases at the top of the drywell causing the cooled gases to gravitate to the bottom of the drywell. The two subsystems are initiated manually. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a limiting single active failure.

The primary containment HMS uses the Drywell Cooling System fans (fan coil units and recirculating fans) to mix the drywell atmosphere. The fan coil units and recirculation fans are automatically disengaged during a LOCA but may be restored to service manually by the operator. In the event of a loss of offsite power, all fan coil units, recirculating fans, and primary containment water chillers are transferred to the emergency diesels. The fan coil

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BASES (continued)

BACKGROUND (continued)

units and recirculating fans are started automatically from diesel power on loss of offsite power.

The function of the recirculating fans is to assist the fan coil units in mixing the drywell air, thus maintaining a uniformly even temperature throughout the drywell space. There are [six] recirculating fans, each provided with its own ductwork.

APPLICABLE SAFETY ANALYSES

The primary containment HMS ensures primary containment OPERABILITY by providing the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.1 volume percent (v/o) following a Design Basis Accident (DBA). This control would prevent a primary containment-wide hydrogen burn, thus ensuring primary containment OPERABILITY and minimizing challenges to the OPERABILITY of safety-related equipment located in primary containment. 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;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS); or

c. Hydrogen in the RCS at the time of the LOCA, that is, hydrogen dissolved in the reactor coolant for control of austenitic stainless-steel intergranular stress corrosion cracking.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated. As such, the primary containment HMS is designed to control an amount of hydrogen generation

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	in primary containment considerably in excess of the amount that would be calculated from the limiting DBA LOCA (Ref. 2). The primary containment HMS satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	[Two] HMS subsystems, including at least one recirculation fan, shall be OPERABLE, powered from independent safety-related power supplies. This ensures operation of at least [one] HMS subsystem in the event of a worst-case single active failure. [For this facility, an OPERABLE HMS subsystem consisting of one Drywell Cooling System train includes the following:] Operation with at least one HMS subsystem provides the capability of controlling the bulk hydrogen concentration in primary containment without exceeding the flammability limit. Unavailability of both trains might lead to primary containment-wide hydrogen burns. [For this facility, the following support systems are required to be OPERABLE to ensure primary containment HMS OPERABILITY:] [For this facility, those required support systems which upon their failure do not require declaring the primary containment HMS inoperable and their justification are as follows:]
APPLICABILITY	Requiring OPERABILITY in MODES 1 and 2 for the primary containment HMS ensures its immediate availability after the safety injection and scram actuated on a LOCA initiation.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

In the post-accident LOCA environment, the two primary containment HMS subsystems ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.1 v/o in primary containment, assuming a worst-case single active failure. This ensures primary containment OPERABILITY and prevents damage to safety-related equipment and instrumentation located within primary containment.

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 these MODES, the probability of an accident requiring the primary containment HMS is low. Therefore, the primary containment HMS is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the primary containment HMS is not required to ensure primary containment OPERABILITY in these MODES.

ACTIONS

A.1

With one required HMS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on the availability of the second subsystem; the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit; the length of time after the event that operator action would be required to prevent this limit from being exceeded; and the availability of the primary containment hydrogen recombiner System, the Standby Gas Treatment System, and the Containment Atmosphere Dilution System.

Concurrent failure of two HMS subsystems within a 30-day period is considered a low probability event. If such a double failure would occur, it would be indicative of poor HMS reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

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BASES (continued)

ACTIONS (continued)

B.1

The plant must be placed in a MODE in which the LCO does not apply if an inoperable HMS subsystem cannot be returned to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 12 hours. The allowed Completion Time is considered reasonable, based on operating experience related to the amount of time required to reach the required MODE from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Operating each HMS subsystem for ≥ 15 minutes ensures that each subsystem is 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. The 92-day Frequency is consistent with the Inservice Inspection and Testing Program Surveillance Frequencies, operating experience, the known reliability of the fan motors and controls, and the two-train redundancy available.

SR 3.6.3.2.2

Demonstrating that each HMS subsystem flow rate is ≥ [500] cfm ensures that each subsystem is capable of maintaining localized hydrogen concentrations below the flammability limit. The 18-month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for unplanned plant transients if the SR is performed with the reactor at power. Operating experience has shown 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.

REFERENCES

1. Regulatory Guide 1.7, "Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident." U.S. Nuclear Regulatory Commission.

2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 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 hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration less than 4.0 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 below 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1) and the primary containment Hydrogen Mixing System (LCO 3.6.3.3) 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 below 4.0 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 is to ensure that oxygen concentration does not exceed 4.0 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 (DBA) loss-of-coolant accident (LOCA) 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 Interim Policy Statement.

(continued)

BASES (continued)

LCO

The primary containment oxygen concentration is maintained below 4.0 v/o to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

[For this facility, the following support systems are required to be OPERABLE to ensure primary containment oxygen concentration equipment OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the primary containment oxygen concentration equipment inoperable and their justification are as follows:]

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 below 15% RATED THERMAL POWER (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 is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

(continued)

BASES (continued)

ACTIONS

A.1

If oxygen concentration exceeds 4.0 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 below 4.0 v/o within 24 hours. The 24-hour Completion Time is allowed when oxygen concentration is above 4.0 v/o because of the availability of other hydrogen-mitigating systems (e.g., hydrogen recombiners) and the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

If equipment used to monitor oxygen concentration in primary containment is determined to be inoperable, the primary containment oxygen concentration is considered to be not within limits and Required Action A.1 applies to restore such equipment to OPERABLE status

B.1

If oxygen concentration cannot be restored to within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by reducing power to ≤ 15% RTP in 8 hours. The 8-hour Completion Time is reasonable, based on operating experience related to the amount of time required to reduce reactor power from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

The primary containment must be determined to be inert by verifying that oxygen concentration is below 4.0 v/o. The 7-day Frequency is based on the slow rate at which oxygen concentration can change and in view of other indications of abnormal conditions (which would lead to more frequent checking by operators per plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

[For this facility, other indications of abnormal conditions that can be used to increase the Frequency for determining

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	oxygen concentration in the primary containment are as follows:] [For this facility, oxygen concentration is measured as follows:]
REFERENCES	1. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.4 Containment Atmosphere Dilution (CAD) System

BASES

BACKGROUND

The CAD System functions to maintain combustible gas concentrations within the primary containment at or below the flammability limits following a postulated loss-of-coolant accident (LOCA) by diluting hydrogen and oxygen with nitrogen. To ensure that a combustible gas mixture does not occur, oxygen concentration is kept below [5.0] volume percent (v/o) or hydrogen concentration is kept below 4.1 v/o.

The CAD System is manually initiated and consists of two independent, 100%-capacity subsystems. Each subsystem includes a liquid nitrogen supply tank, ambient vaporizer, electric heater, and connected piping to supply the drywell and suppression chamber volumes. The nitrogen storage tanks each contain ≥ [4350] gal, which is adequate for [7] days of CAD subsystem operation.

The CAD System operates in conjunction with emergency operating procedures that are used to reduce primary containment pressure periodically during CAD System operation. This combination results in a feed-and-bleed approach to maintaining hydrogen and/or oxygen concentrations below combustible levels.

APPLICABLE SAFETY ANALYSES

To evaluate the potential for hydrogen and oxygen accumulation in primary containment following a LOCA, hydrogen and oxygen generation is calculated (as a function of time following the initiation of the accident). The assumptions stated in Reference 1 are used to maximize the amount of hydrogen and oxygen generated. The calculation confirms that when the mitigating systems are actuated in accordance with emergency operating procedures, the peak oxygen concentration in primary containment is < [5.0] v/o (Ref. 2).

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	Hydrogen and oxygen may accumulate within Primary Containment following a LOCA as a result of: a. A metal-water reaction between the zirconium fuel-rod cladding and the reactor coolant; b. Radiolytic decomposition of water in the Reactor Coolant System (RCS); or c. Hydrogen in the RCS at the time of the LOCA, i.e., hydrogen dissolved in the reactor coolant for the control of austenitic stainless-steel intergranular stress corrosion cracking. The CAD System satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	Two CAD subsystems must be OPERABLE. This assures operation of at least one CAD subsystem in the event of a worst-case single active failure. Operation of at least one CAD subsystem is designed to maintain primary containment post-LOCA oxygen concentration below 5.0 v/o for 7 days. [For this facility, an OPERABILITY CAD subsystem constitutes the following:] [For this facility, the following support systems are required OPERABLE to ensure CAD System OPERABILITY:] [For this facility, those required support systems which upon their failure do not require declaring the CAD System inoperable and their justification are as follows:]
APPLICABILITY	In MODES 1 and 2, the CAD System is required to maintain the oxygen concentration within primary containment below the flammability limit of 5.0 v/o following a LOCA. This ensures that the relative leak tightness of primary containment is adequate and prevents damage to safety-related equipment and instruments located within primary containment.

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BASES (continued)

APPLICABILITY (continued)

In MODE 3, both the hydrogen and oxygen production rates and the total amounts produced after a LOCA would be less than those calculated for the Design Basis Accident (DBA) LOCA. Thus, if the analysis were to be performed starting with a LOCA in MODE 3, the time to reach a flammable concentration would be extended beyond the time conservatively calculated for MODES 1 and 2. The extended time would allow hydrogen removal from the primary containment atmosphere by other means and also allow repair of an inoperable CAD subsystem, if CAD were not available. Therefore, the CAD System is not required to be OPERABLE in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations of these MODES. Therefore, the CAD System is not required to be OPERABLE in MODES 4 and 5 to ensure primary containment OPERABILITY.

ACTIONS

A.1

If one CAD subsystem is inoperable, it must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limit; the length of time after the event that operator action would be required to prevent this limit from being exceeded; and the availability of the second CAD subsystem and other hydrogen-mitigating systems.

Required Action A.1 has been modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one CAD subsystem is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE subsystem, the length of time after a postulated LOCA before operator action would be required to prevent the flammability limit from being exceeded, and the availability of other hydrogen-mitigating systems.

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BASES (continued)

ACTIONS (continued)

Concurrent failure of two CAD subsystems within a 30-day period is considered a low-probability event. If such a double failure did occur, it would be an indication of poor CAD reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

If the CAD subsystem cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience related to the amount of time required to reach the required MODE from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4.1

Verifying that there is at least [4350] gal of liquid nitrogen supply in each CAD subsystem will ensure at least [7] days of post-LOCA CAD operation. This minimum volume of nitrogen allows sufficient time after an accident to replenish the nitrogen supply for long-term inerting. This is verified every 31 days to ensure that the system is capable of performing its intended function when required. The 31-day Frequency is based on operating experience, which has shown 31 days to be an acceptable period to verify the liquid nitrogen supply and on the availability of other hydrogen-mitigating systems.

SR 3.6.3.4.2

Verifying the correct alignment for manual, power-operated, and automatic valves in each of the CAD subsystem flow paths provides assurance that the proper flow paths exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

A valve is also allowed to be in the non-accident position provided it can be aligned to its accident position. This is acceptable because the CAD System 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. The 31-day Frequency of this SR was developed based on Inservice Inspection and Testing Program requirements to perform valve testing at least once per 92 days.

REFERENCES

1. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident," Revision 2, November 1978.

2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The primary containment is designed to maintain its OPERABILITY during and following any postulated loss-of-coolant accident (LOCA). During a postulated LOCA, fission products are released directly to the primary containment. The design basis leakage rate for the primary containment and its penetrations (excluding the main steam lines) is 0.35% per day for the duration of the accident.

The function of the secondary containment is to isolate and contain fission products that escape from primary containment following a Design Basis Accident (DBA), to confine the postulated release of radioactive material within the requirements of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits), 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 plant design basis postulates that a non-isolable release of significant fission products can occur only inside the primary containment. Since the primary containment is a high-pressure leak-tight barrier, the bulk of these fission products is expected to remain entrapped within the primary containment and the primary containment is expected to maintain release rates below those required by 10 CFR 100.

As an extra barrier to accommodate small quantities of fission products that may escape from primary containment, a secondary containment has been provided. Additionally, the secondary containment is the required fission-product barrier for some plant operations that occur outside primary containment (e.g., handling irradiated fuel) or occur when the primary containment need not be OPERABLE.

The secondary containment is a structure with a known leakage rate 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

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BASES (continued)

BACKGROUND (continued)

products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump/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 System (SGTS)."

APPLICABLE SAFETY ANALYSES

The secondary containment provides a dilution and hold-up volume for fission products that may leak from the primary containment following a postulated accident. In conjunction with operation of the SGTS, the secondary containment is designed to limit the thyroid dose and the whole-body dose resulting from a LOCA to within the guidelines of 10 CFR 100 or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a LOCA (Ref. 2) and a fuel-handling accident inside secondary containment (Ref. 3). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to limit offsite radiation doses to below those required by 10 CFR 100. Maintaining secondary containment OPERABLE ensures that the release of radioactive materials from the primary containment is restricted to those leakage paths and associate leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated prior to discharge to the environment.

Secondary containment satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from

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BASES (continued)

LCO (continued)

primary containment or escape 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.

The secondary containment LCO requires that secondary containment OPERABILITY be maintained. [For this facility, other secondary containment LCOs support this LCO by ensuring:]

The Required Actions when other secondary containment LCOs are not met have been specified in those LCOs and not in LCO 3.6.4.1.

[For this facility, an OPERABLE secondary containment constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure secondary containment OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the secondary containment inoperable and their justification are as follows:]

APPLICABILITY

Maintaining secondary containment OPERABILITY prevents leakage of radioactive material from the secondary containment. 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 Reactor Coolant System (RCS) pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODES 4 or 5 to ensure primary containment OPERABILITY, except for other situations for which

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BASES (continued)

APPLICABILITY (continued)

significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during the handling of irradiated fuel assemblies or other loads over irradiated fuel assemblies.

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 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 in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

Irradiated fuel handling in the secondary containment, moving loads over irradiated fuel, 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 handling of irradiated fuel or other loads 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, if applicable, action must be immediately

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BASES (continued)

ACTIONS (continued)

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 that states that LCO 3.0.3 is not applicable. If handling fuel while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, in either case, inability to suspend handling of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. However, the secondary containment in MODES 1, 2, and 3 must be restored to OPERABLE status within the specified time of 4 hours or the plant must be placed in a MODE in which the LCO does not apply, including entering LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

It has been established (Ref. 3) that the secondary containment should be ≥ [0.25] inches of vacuum water gauge under all wind conditions up to the wind speed at which diffusion becomes great enough to ensure site-boundary exposures less than those with a LOCA, even if exfiltration were to occur. In this manner, the inleakage of fresh air negates the tendency of the fission products to exfiltrate through the secondary containment barrier if the secondary containment were inoperable. This SR ensures that secondary containment remains within the specified limit. The 24-hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations and 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 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Additionally, exterior environmental disturbances (e.g., wind gusts) cannot cause the secondary containment to experience a positive pressure relative to the environment. Verifying that all such openings are closed provides adequate assurance that infiltration/exfiltration from the secondary containment will not occur. Maintaining secondary containment OPERABILITY requires maintaining each door in the access opening 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 is based on engineering judgment, 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

Performance of this surveillance would give advance indication of gross determination of the concrete structural integrity of the secondary containment. The Frequency of this SR is the same as that of SR 3.6.1.1.1. The verification is done during shutdown and as part of Type A leakage tests associated with SR 3.6.1.1.1.

SR 3.6.4.1.5 and SR 3.6.4.1.6

The SGTS exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all untreated fission products are treated, SR 3.6.4.1.5 demonstrates that the SGTS 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 SGTS subsystem will draw down the secondary containment to ≥ [0.25] inches of vacuum water gauge in ≤ [120] seconds. This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.6 demonstrates that one SGTS subsystem can maintain ≥ [0.25] inches of vacuum water gauge over a 1 hour period at a flow rate of ≤ [4000] cfm. 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 OPERABILITY. Since these SRs are secondary containment

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	tests, they need not be performed with each SGTS subsystem. The SGTS subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGTS will perform this test. While this SR can be performed with the reactor at power, 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.
REFERENCES	1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance." 2. [Unit Name] FSAR, Section [ ], "[Title]." 3. [Unit Name] FSAR, Section [ ], "[Title]."

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) such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 (Ref. 5) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that escape from primary containment following a DBA, or which 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. Locked-closed manual valves, deactivated automatic valves secured in their closed position, blind flanges, and closed systems are considered passive 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 (and possibly loss of secondary containment OPERABILITY).

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

[For this facility the secondary containment isolation signals are as follows:]

Other penetrations are isolated by the use of valves in the closed position or blind flanges. OPERABILITY of SCIVs (and blind flanges) ensures that secondary containment OPERABILITY is maintained during accident conditions.

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BASES (continued)

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-coclant accident (LOCA) (Ref. 2) and a fuel-handling accident inside secondary containment (Ref. 3). The secondary containment performs no active function in response to each of these limiting events, but its leak tightness is required to limit offsite radiation releases to below those levels required by 10 CFR 100, or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

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

SCIVs satisfy Criterion 3 of the NRC Interim 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 (including specific operations when primary containment is not required to be OPERABLE) to within 10 CFR 100 limits.

The automatic 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 4.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are locked-closed, automatic valves are deactivated and secured in their closed position, and blind flanges and closed systems are in place. These passive isolation valves or devices are listed in Reference 4.

[For this facility, OPERABILITY of SCIVs requires OPERABILITY of the following support systems:]

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BASES (continued)

LCO (continued)

[For this facility, those required support systems which upon their failure do not require declaring the SCIVs inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a SCIV and the justification of whether or not each supported system is declared inoperable are as follows:]

This LCO provides assurance that the SCIVs will perform their intended safety functions to mitigate the consequences of accidents that could result in offsite radiation releases that exceed the 10 CFR 100 limits or some fraction of these limits as established by the NRC staff-approved licensing basis.

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.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the Reactor Coolant System pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODES 4 or 5 to back up primary containment OPERABILITY, 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), CORE ALTERATIONS, the handling of irradiated assemblies, or when moving loads over irradiated fuel assemblies. Moving irradiated fuel assemblies in the secondary containment or moving loads over irradiated fuel assemblies may also occur in MODES 1, 2, and 3.

A Note has been added to provide clarification that each penetration flow path is independent and is treated as a separate entity with a separate Completion Time for the purpose of this LCO.

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BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2.1, and A.2.2.2

With one or more SCIVs inoperable, at least one isolation valve must be verified to be OPERABLE in each affected open penetration. This action may be satisfied by examining logs or other information to determine whether the valve is out of service for maintenance or other reasons. This Required Action is to be completed within 1 hour in order to provide assurance that a secondary containment penetration is not open and causing a loss of secondary containment OPERABILITY. The 1-hour Completion Time is considered a reasonable length of time needed to complete the Required Action, and it is the same Completion Time used for primary containment isolation valves (PCIVs)in LCO 3.6.1.3.

In the event that one or more SCIVs are inoperable, either the inoperable valve must be restored to OPERABLE status or the affected penetration 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 criteria are a closed and deactivated automatic SCIV, a closed manual valve, or a blind flange. For penetrations isolated in accordance with Required Action A.2.2.1, the valve used to isolate the penetration should be the closest available valve to secondary containment. One of these two Required Actions must be completed within the 4-hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and it is the same Completion Time used for PCIVs in LCO 3.6.1.3.

For affected penetrations that cannot be restored to OPERABLE status within the 4-hour Completion Time and have been isolated in accordance with Required Action A.2.2.1, the affected 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 are no longer capable of being automatically isolated, will be in the isolation position should an event occur. The 31-day Completion Time is based upon Inservice Inspection and Testing Program Requirements to perform valve testing at least once per 92 days. This Required Action does not require any testing or valve

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BASES (continued)

ACTIONS (continued)

manipulation. Rather, it involves verification, through a system walkdown, that those valves capable of potentially being mispositioned are in the correct position.

The Required Actions of Condition A are modified by a Note allowing normally locked- and sealed-closed SCIVs to be opened 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 valid secondary containment isolation signal is indicated. The provisions of LCO 3.0.4 apply.

Required Actions of Condition A are further modified by a second Note stating that Required Action A.1 is not applicable to penetrations that have only one isolation valve. If the single isolation valve is inoperable, the intent is to go directly to Required Action A.2.1.

[For this facility, systems with single isolation valves are as follows:]

The justification for a Completion Time of 4 hours is similar to that for lines with two isolation valves.

[For this facility, the second Note applies only to the following type of lines:]

B.1

With one or more SCIVs inoperable in one or more penetration flow paths, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support SCIVs within the Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition B.

Required Action B.1 ensures that those identified Required Actions associated with supported systems impacted by the

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BASES (continued)

ACTIONS (continued)

inoperability of SCIVs have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions need to be initiated every time Condition B is entered. [For this facility, the identified supported systems Required Actions are as follows:]

C.1

With one or more SCIVs inoperable in one or more penetration flow paths AND one or more support or supported features, or both, inoperable associated with the other redundant penetration flow paths, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the support or supported feature LCO, or both, take into consideration the loss of function, then LCO 3.0.3 may not need to be entered.

An example illustrating the loss of function situation is presented in B 3.6.1.3, "Primary Containment Isolation Valves."

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the Required Actions and associated Completion Times are not met. This is done by placing the plant in at least MODE 3 within 12 hours and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

The plant must be placed in a condition in which the LCO does not apply if the Required Actions and associated Completion Times are not met. If applicable, CORE ALTERATIONS and the handling of irradiated fuel or other loads 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

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BASES (continued)

ACTIONS (continued)

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 C.1 has been modified by a Note which states that LCO 3.0.3 is not applicable. If handling fuel while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, in either case, inability to suspend handling of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown. However, SCIVs in MODES 1, 2, and 3 must be restored to OPERABLE status or isolated within the specified time of 4 hours, or the plant must be placed in a MODE in which the LCO does not apply, including entering LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that all manual SCIVs and blind flanges that are required to be closed during accident conditions are 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. The 31-day Frequency of this SR was developed based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once 92 days. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves in secondary containment that are capable of potentially being mispositioned are in the correct position.

Since these valves are readily accessible to personnel during normal plant 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.

Several Notes have been added to this SR. The first Note applies to valves and blind flanges located in high-radiation areas and allows these valves to be verified as

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

closed 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 as low as reasonably achievable 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 added that allows normally locked-or sealed-closed isolation valves to be opened under administrative controls. These administrative 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 valid secondary containment isolation signal is indicated.

A third Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open. The provisions of LCO 3.0.4 apply.

SR 3.6.4.2.2

Demonstrating that the isolation time of each power-operated and 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 are in accordance with the Inservice Inspection and Testing Program, but the Frequency must not exceed 92 days.

SR 3.6.4.2.3

In the secondary containment, the check valves that serve a containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. SR 3.6.4.2.3 verifies the operation of the check valves that are testable during plant operation. The Frequency of 92 days is consistent with the Inservice Inspection and Testing Program requirement for valve testing on a 92-day Frequency.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.4

Automatic SCIVs close on a secondary containment isolation signal 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 its isolation position on a secondary containment isolation signal. While this SR can be performed with the reactor at power, 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.

SR 3.6.4.2.5

In the secondary containment, the check valves that serve a containment isolation function are weight- or spring-loaded to provide positive closure in the direction of flow. This ensures that these check valves will remain closed. SR 3.6.4.2.5 verifies the operation of the check valves that are not testable during plant operation. The Frequency of 18 months is based on such factors as the inaccessibility of these valves, the fact that the plant must be shut down to perform the tests, and the successful results of the tests on an 18-month basis during past plant operation.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. [Unit Name] FSAP, Section [ ], "[Title]."

4. [Unit Name] FSAR, Section [ ], "[Titl.[illegible]"

5. Title 10, Code of Federal Regulations, [illegible]t 100.11, "Determination of Exclusion Area, Low P[illegible]lation Zone, and Population Center Distance."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment System (SGTS)

BASES

BACKGROUND

The SGTS is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1), 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. This system reduces the potential releases of radioactive material, principally iodine, to within values specified in 10 CFR 100 (Ref. 2) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

The SGTS consists of the following components:

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

   1. a demister or moisture separator,
   2. an electric heater,
   3. a pre-filter,
   4. a high efficiency particulate air (HEPA) filter,
   5. a charcoal adsorber,
   6. a second HEPA filter, and
   7. a centrifugal fan; and

b. Two fully redundant subsystems, each with its own set of ductwork, dampers, and controls.

The sizing of the SGTS 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 SGTS boundary region is maintained at a negative pressure of [0.25] inches water gauge (Ref. 3) when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building when exposed to a [10] mph wind blowing at an angle of [45] degrees to the building. The demister is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than [70]% (Ref. 4). The prefilter

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BASES (continued)

BACKGROUND (continued)

removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SGTS automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both charcoal filter train fans start. Upon verification that both trains are operating, the redundant train is normally shut down.

APPLICABLE SAFETY ANALYSES

The design basis for the SGTS is to mitigate the consequences of a loss-of-coolant accident (LOCA) and fuel-handling accidents (Ref. 4 and 5). For all events analyzed, the SGTS is shown to be automatically initiated to limit, via filtration and absorption, the site-boundary radioactivity dose level to well within the 10 CFR 100 limits.

The acceptance criteria applied to accidental releases of radioactive material to the environment are given in terms of total radiation dose received by:

1. A member of the general public who remains at the exclusion-area boundary for 2 hours following the onset of the postulated fission-product release; or

2. A member of the general public who remains at the low-population-zone boundary for the duration of the accident.

The limits established in 10 CFR 100 are a whole-body dose of 25 rem, or a dose of 300 rem to the thyroid from iodine exposure, or both. The NRC staff-approved licensing basis may use some fraction of these limits.

The SGTS satisfies Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

Following a DBA, a minimum of one SGTS subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. To ensure that this requirement is met, two subsystems must be OPERABLE. Thus, meeting the LCO requirements assures operation of at least one SGTS subsystem in the event of a single active failure.

[For this facility, an OPERABLE SGTS constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure SGTS OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the SGTS inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a SGTS and the justification of whether or not each supported system is declared inoperable are as follows:] It should be noted that LCO 3.6.4.3 may need to be augmented with additional Conditions if it is determined that SGTS provides support to other systems included in the Technical Specifications.

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, SGTS 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 SGTS in OPERABLE status 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 CORE ALTERATIONS, during handling of irradiated fuel assemblies in the [secondary containment], or moving other loads over irradiated fuel assemblies.

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BASES (continued)

ACTIONS

A.1

With one SGTS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status in 7 days. The 7-day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGTS and the low probability of a DBA occurring during this period.

A concurrent failure of two SGTS subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the SGTS cannot be restored to OPERABLE status in the associated Completion Time in MODE 1, 2, or 3. This is done by placing the plant 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 related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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

During handling of irradiated fuel, moving other loads over irradiated fuel, CORE ALTERATIONS, or OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGTS subsystem should immediately be placed in operation. This action ensures that the remaining subsystem 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 C.1 is to 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, handling of irradiated fuel, or moving other loads over irradiated fuel must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe

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BASES (continued)

ACTIONS (continued)

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.

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

When two SGTS subsystems are inoperable, if applicable, CORE ALTERATIONS, handling of irradiated fuel in secondary containment, or moving other loads over irradiated fuel must immediately be suspended. Suspension of these activities shall 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGTS subsystem for ≥ [10] hours ensures that both subsystems 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] 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 two-train redundancy available.

SR 3.6.4.3.2

The Ventilation Filter Testing Program (VFTP) (Specification 5.8.4.S) encompasses all the SGTS filter tests consistent with Regulatory Guide 1.52 (Ref. 6). 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

and additional information are discussed in detail in the VFTP. The following tests are included:

a. Verification of the in-place (cold) penetration and bypass dioctyl phthalate (DOP) test leakage of each SGTS train (the cold DOP test confirms the validity of the pre-installation hot DOP test and allows proper filter performance to be inferred);

b. Verification of the in-place penetration and bypass halogenated hydrocarbon refrigerant gas test leakage of each SGTS train (this test determines that no bypass paths exist through or around the charcoal adsorber bed);

c. Verification of the methyl iodide penetration of a charcoal sample from each filter bed (this test verifies that the charcoal adsorption capability is within required limits),

d. Verification that the flow rate of each SGTS train and the pressure drop across the combined prefilters, HEPA filters, and charcoal adsorber banks are within the required limits; and

e. Verification, for systems with heaters, of the proper function of each SGTS train's heaters.

SR 3.6.4.3.3

This SR demonstrates that each SGTS subsystem starts on receipt of a simulated or actual initiation signal. While this SR can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR demonstrates that the cooler bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGTS operation is available. While this SR can be performed with the reactor at power, operating experience has shown that these components usually pass the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR when performed on the 18-month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup."

2. Title 10, Code of Federal Regulations, Part 100.11 "Determination of Exclusion Area Low Population Zone and Population Center Distance."

3. NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Branch Technical Position, CSB 6-3, "Determination of Bypass Leakage Paths in Dual Containment Plants."

4. [Unit Name] FSAR, Section [ ], "[Containment Systems]."

5. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."

6. Regulatory Guide 1.52, Rev. 2, "Design, Testing and Maintenance Criteria for Post Accident Engineered Safety Feature Atmospheric Cleanup System Air Filtration and Absorption Units of Light-Water Cooled Nuclear Power Plants."

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers which are required for a safe reactor shutdown following a design basis transient or accident. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling or spray mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, two [4000] gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with one pump operating to maintain safe shutdown conditions. The two subsystems are separated from each other by normally closed motor-operated cross-tie valves, so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in Reference 1.

Cooling water is pumped by the RHRSW pumps from an ultimate heat sink (UHS) water source, through the tube side of the RHR heat exchangers, and discharges to the [cooling towers where the heat is rejected through direct contact with ambient air]. A minimum-flow line from the pump discharge to the intake prevents the pump from overheating when pumping against a closed discharge valve. The UHS is considered part of the Plant Service Water (PSW) System (see LCO 3.7.2) and is described in B 3.7.2.

The system is initiated manually from the control room. If operating during a loss-of-coolant accident (LOCA), the system is automatically tripped to allow the emergency diesel generators (EDGs) to automatically power only that equipment necessary to reflood the core. The system can be manually started any time 10 minutes after the LOCA, or manually started any time the LOCA signal is manually or automatically overridden.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long-term cooling of the reactor or primary containment is discussed in References 2 and 3. These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long-term primary containment response after a design basis LOCA.

The safety analyses for long-term cooling were performed for various combinations of RHR System failures. The worst-case single failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. For these analyses (Ref. 2), manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur [10] minutes after a Design Basis Accident (DBA). The RHRSW flow assumed in the analyses is [4000] gpm per pump with two pumps operating in one loop. In this case, the maximum suppression chamber water temperature and pressure are [206.4]°F and [36.59] psig, respectively, well below the design temperature of [340]°F and maximum allowable pressure of [62] psig.

The RHRSW System satisfies of Criterion 3 of the NRC Interim Policy Statement.

LCO

Two RHRSW subsystems provide the required redundancy to ensure that the system functions to remove post-accident heat loads, assuming the worst-case single active failure occurs coincident with the loss-of-offsite power.

A typical subsystem is considered OPERABLE when it has two OPERABLE pumps and an OPERABLE flow path capable of taking suction from a UHS water source and transferring the water to the RHR heat exchangers at the assumed flow rate. Additionally, the RHRSW cross-tie valves (which allow the two RHRSW loops to be connected) must be closed so that failure of one subsystem will not affect the OPERABILITY of the other subsystems.

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BASES (continued)

LCO (continued)

An adequate suction source is not addressed in this LCO since the minimum net positive suction head (NPSH) ([ ] ft Mean Sea Level in the pump well) is bounded by the PSW pump requirements (LCO 3.7.2).

[For this facility, an OPERABLE RHRSW subsystem consists of the following:]

[For this facility, the following support systems must be OPERABLE to ensure RHRSW System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the RHRSW System inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of the RHRSW System and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, the RHRSW System is required to be OPERABLE to support the OPERABILITY of the RHR System for primary containment cooling (LCO 3.6.2.3 and LCO 3.6.2.4) and decay-heat removal (LCO 3.4.6). Therefore, the applicability is consistent with these systems' requirements.

In MODES 4 and 5, the OPERABILITY requirements of the RHRSW System are determined by the systems it supports.

For this LCO, a Note has been added to provide clarification that all components of the RHRSW System are treated as an entity with a single Completion Time.

ACTIONS

A.1

If one RHRSW pump is inoperable, it must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RHRSW pumps are adequate to perform the RHRSW heat-removal function. Overall reliability is reduced, however, because a single failure in the OPERABLE subsystems could result in reduced RHRSW capability. The

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BASES (continued)

ACTIONS (continued)

30-day Completion Time is based on the remaining RHRSW heat-removal capability, including enhanced reliability afforded by manual cross-connect capability, and the low probability of a DBA with concurrent worst-case single failure. [For this facility, an inoperable pump consists of the following:]

B.1

Required Action B.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. The Completion Time was chosen in light of the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event requiring RHRSW occurring during this period.

C.1

With one RHRSW subsystem inoperable, verify that the Required Actions have been initiated for those supported systems declared inoperable by the inoperability of the support RHRSW subsystem within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of one or more support features specified under Condition C.

Required Action C.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of RHRSW subsystem have been initiated by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Conditions C of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

D.1

With one RHRSW subsystem inoperable, and one or more required support or supported features inoperable associated

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BASES (continued)

ACTIONS (continued)

with the other redundant RHRSW subsystem; a loss of function capability results, and LCO 3.0.3 must be entered immediately. However, if the support or supported features' LCOs take into consideration the loss-of-function situation, then LCO 3.0.3 may not need to be entered.

An example illustrating this situation would be when a support RHRSW subsystem is declared inoperable, the redundant counterpart supported RHR system and its support systems must be OPERABLE, otherwise a loss-of-functional capability exists. A loss-of-functional capability in this case may place the operation of the plant outside the safety analysis. Therefore, immediate actions must be taken to bring the plant to a MODE outside the Applicability of the LCO for the RHRSW system.

E.1

With both RHRSW subsystems inoperable for whatever reasons, the RHRSW System will not be capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 1 hour. The Completion Time is consistent with the time provided by LCO 3.0.3, involving loss of function situations.

[For this facility, the Completion Time of 1 hour can be extended for the following reasons:]

F.1 and F.2

If the RHRSW subsystems are not restored to OPERABLE status within the associated Completion Times, the plant must be placed in MODE 3 within 12 hours and subsequently in MODE 4 within 36 hours. If MODE 4 cannot be achieved because of the inoperable RHRSW subsystems, the reactor coolant temperature should be maintained as low as practicable, using an alternate decay-heat-removal method. In MODE 4, system requirements are specified in LCO 3.7.2. [For this facility, an alternate decay-heat-removal method consists of the following:] The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the RHRSW flow path provides assurance that the proper flow paths will exist for RHRSW 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 non-accident position, provided it can be aligned to its accident position. This is acceptable because the RHRSW system is a manually initiated system. 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 31-day Frequency of this SR was derived from Inservice Inspection and Testing Program requirements for performing valve testing at lease once every 92 days. The Frequency was further justified in view of other procedural controls governing valve operation and as a means of providing assurance of correct valve positions.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. [Unit Name] FSAR, Chapter [15], "[Accident Analysis]."
3. [Unit Name] FSAR, Chapter [6], "[Engineered Safety Features]."

B 3.7 PLANT SYSTEMS

B 3.7.2 [Plant] Service Water (PSW) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The [Plant] Service Water (PSW) System is designed to provide cooling water for the removal of heat from equipment, such as the emergency diesel generators (EDGs), residual heat removal (RHR) pump coolers, and room coolers for Emergency Core Cooling System (ECCS) equipment, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The PSW System also provides cooling to plant components, as required, during normal operation. Upon receipt of a loss-of-offsite power or loss-of-coolant-accident (LOCA) signal, non-essential loads are automatically isolated, the essential loads are automatically divided between PSW Divisions I and II, and one PSW pump is automatically started in each division.

The PSW System consists of the UHS and two independent cooling water headers (subsystems A and B); each of the latter with two pumps and their associated piping, valves, and instrumentation. Each of the two PSW pumps in each subsystem is sized so either can provide sufficient cooling capacity to support the required safety-related systems during safe shutdown of the unit following a LOCA. Subsystems A and B are redundant and separated from each other so failure of one subsystem will not affect the OPERABILITY of the other. Cooling water for the RHR System heat exchangers required for a safe reactor shutdown following a DBA or transient is provided by the Residual Heat Removal Service Water (RHRSW) System (see LCO 3.7.1).

The UHS has been defined as that complex of water sources, including necessary retaining structures (e.g., a pond with its dam or a river with its dam), and the canals or conduits connecting with the sources (Ref. 1). If cooling towers or portions thereof are required to accomplish the UHS safety functions, they should satisfy the same requirements as the sink. The two principal safety functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

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BASES (continued)

BACKGROUND (continued)

A variety of complexes are used to meet the requirements for a UHS. A lake or an ocean may qualify as a single source. If the complex includes a water source contained by a fabricated structure, it is likely that a second source will have been required.

The basic performance requirements are that a 30-day supply of water (Ref. 1) be available and that the design bases temperatures of safety-related equipment are not exceeded. Basins of cooling towers generally include less than a 30-day supply of water, typically 7 days or less. Assurance of a 30-day supply is then dependent on other sources and makeup systems for replenishing the source in the cooling tower basin. For smaller basin sources, which may be as small as a 1-day supply, the systems for replenishing the basin and the backup sources become sufficiently important that the makeup system itself may be required to meet the same design criteria as an engineering safety feature (ESF) (e.g., single feature considerations), and multiple makeup water sources may be required.

It follows that the many variations in the UHS configurations will result in many plant-to-plant variations in OPERABILITY determinations and in SRs. The Actions and SRs for this LCO are illustrative for a UHS consisting of a cooling tower with makeup water and a river.

A typical cooling tower UHS complex consists of one or more concrete makeup water basins with one or more cooling towers, two or more independent fan cells per cooling tower (for one division), and cooling water pumped from a river (for the other division). Cooling water is pumped from the cooling tower basin and river by either of the two PSW pumps in each subsystem to the essential components through the two main redundant supply headers (subsystems A and B). After removing heat from the components, the water from one division is discharged to the cooling tower where the heat is rejected through direct contact with ambient air and then returned to the makeup water basin. Water from the other division is discharged to the river. Normal makeup for the basin is provided automatically by the PSW System.

Subsystems A and B supply cooling water to redundant equipment required for a safe reactor shutdown. Additional information on the design and operation of the PSW System

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BASES (continued)

BACKGROUND (continued)

and UHS, along with the specific equipment for which the PSW System supplies cooling water, is described in Reference 2. The PSW 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 PSW System will operate automatically without operator action.

APPLICABLE SAFETY ANALYSES

The volume of each water source incorporated in an UHS complex is sized such that sufficient water inventory is available for all PSW System post-LOCA cooling requirements for a 30-day period with no additional makeup water source available (Ref. 2). The ability of the PSW System to support long-term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in References 2, 3, and 4. These analyses include the evaluation of the long-term primary containment response after a design basis LOCA. The PSW System provides cooling to various components assumed to function during a LOCA (e.g., RHR, core spray, and RHRSW pumps). Also, the ability to provide onsite emergency AC power is dependent on the ability of the PSW System to cool the EDGs.

[The safety analyses for long-term containment cooling were performed (Ref. 4) for a LOCA concurrent with a loss-of-offsite power, and minimum available EDG power. The worst-case single failure that would affect the performance of the PSW System is the failure of one of the two EDGs that would in turn affect one PSW subsystem. Reference 2 discusses PSW System performance during these conditions.]

The PSW System together with the UHS satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

The OPERABILITY of subsystem A (Division I) and subsystem B (Division II) of the PSW System is required to ensure the effective operation of the RHR System in removing heat from

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BASES (continued)

LCO (continued)

the reactor, and the effective operation of other safety-related equipment during a DBA or transient. Requiring both subsystems to be OPERABLE ensures either subsystem A or B 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.

An OPERABLE subsystem has an OPERABLE UHS with both of the associated pumps OPERABLE, and an OPERABLE flow path capable of taking suction from the associated PSW cooling water source and transferring the water to the appropriate plant equipment. OPERABILITY of the UHS is based on a maximum water temperature of [90]°F with OPERABILITY of subsystem A requiring a minimum basin water level at or above elevation [ ]ft [ ]inches mean sea level (which is equivalent to an indicated level of ≥ [ ] ft), and [two] OPERABLE cooling tower fans; and OPERABILITY of subsystem B requiring a minimum water level in the pump well of the intake structure of [ ]ft [ ]inches mean sea level (or to an indicated level of ≥ [ ] ft).

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

[For this facility, the following support systems must be OPERABLE to ensure PSW System and UHS OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the PSW System and UHS inoperable and their justification are as follows:]

[For this facility, the following supported systems are impacted by the inoperability of the PSW System and UHS and the justification for whether or not each supported system is declared inoperable:]

APPLICABILITY

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

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BASES (continued)

APPLICABILITY (continued)

In MODES 4 and 5, the OPERABILITY requirements of the PSW System are determined by the systems they support.

A Note has been added to provide clarification that for this LCO, all components of the PSW System and UHS are treated as an entity with a single Completion Time.

ACTIONS

A.1

With one PSW pump inoperable in one of the subsystems, the inoperable pump must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE PSW pumps (even allowing for an additional single failure) are adequate to perform the PSW heat-removal function. The overall reliability is reduced, however. The 30-day Completion Time is based on the remaining PSW heat-removal function to accommodate an additional single failure, and the low probability of an event during this time period. [For this facility, an inoperable pump consists of the following:]

B.1

With one PSW pump inoperable in both of the subsystems, one of the inoperable pumps must be restored to OPERABLE status within 7 days and the other must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE PSW pumps (even allowing for an additional single failure) are adequate to perform the PSW heat-removal function. The overall reliability is reduced, however. The 7-day and 30-day Completion Times are based on the remaining PSW heat-removal function to accommodate an additional single failure and the low probability of an event during this time period.

C.1 and C.2

Required Action C.1 assures that the required cooling capacity will be available in the event of a DBA.

This Action may be satisfied by examining logs or other information to determine whether the cooling tower fans may

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BASES (continued)

ACTIONS (continued)

be out of service for maintenance or other reasons. It does not mean that it is necessary to perform the SRs needed to demonstrate OPERABILITY of the fan. If there is not one cooling tower fan per cooling tower OPERABLE, Condition G must be immediately entered. The Completion Time of 1 hour is sufficient for plant operation personnel to make this determination.

For Action C.2, if one cooling tower fan per cooling tower is inoperable, the inoperable cooling tower fans must be restored to OPERABLE status within 7 days before action must be taken to reduce power. The specified Completion Time is consistent with other LCOs for loss of one-half of a 200%-capacity train of an ESF System.

The 7-day Completion Time is based on the low probability of an accident occurring during the 7 days that one cooling tower fan is inoperable, the number of available systems, and the time required to reasonably complete the Required Action.

D.1

With one PSW subsystem inoperable for reasons other than Condition A, 72 hours are allowed to restore the PSW subsystem to OPERABLE status. The allowed Completion Time takes into account the redundant PSW system capabilities afforded by the OPERABLE subsystem and the low probability of an accident during this time period, and is consistent with the allowed Completion Time to restore an inoperable EDG or one low-pressure ECCS division to OPERABLE status.

E.1

With one PSW subsystem inoperable, or less than [one] cooling tower fan(s) inoperable in one or more cooling tower, or both instances, verify that the Required Actions have been initiated for those supported systems declared inoperable by the inoperability of the support PSW subsystem or cooling tower fan(s) within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that needed to be declared inoperable upon the failure of

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(continued)

BASES (continued)

ACTIONS (continued)

one or more support features specified under Condition E.

Required Action E.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of PSW subsystem or cooling tower fans have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions need to be initiated every time Condition E is entered. [For this facility, the following identified supported systems are Required Actions:]

F.1

With one PSW subsystem inoperable, or no more than [one] cooling tower fan(s) inoperable in one or more cooling towers, or both instances; and one or more required support or supported features inoperable that are associated with the other redundant PSW subsystem or cooling tower fans; a loss-of-function capability results, and LCO 3.0.3 must be immediately entered. However, if the support or supported features' LCOs take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

G.1 and G.2

If the Required Actions and associated Completion Times are not met, or both PSW subsystems are inoperable for reasons other than Condition B, or the UHS is determined inoperable for reasons other than Condition C, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant 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 MODES from full power in an orderly manner and without challenging plant systems.

This Condition includes the situation where MODE 4 may not be achievable within the specified Completion Time because of the inoperable PSW subsystems, in which case the reactor coolant temperature should be maintained as low as practicable using an alternative decay-heat-removal method. When an adequate complement of components is available, the plant should be placed in MODE 4. [For this facility, an alternate decay-heat-removal method consists of the following:]

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This surveillance verifies that the cooling tower basins have sufficient cooling water (as measured by basin water level) to satisfy the design basis of 30-day cooling capability with no external makeup source. With the UHS water source below the minimum level, the affected PSW subsystem 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 inside the pump wells of the intake structure to be sufficient for the proper operation of the PSW pumps (net positive suction head and pump vortexing are considered in determining this limit). If a temporary weir is in place, the [river] level must also correspond to the level in the pump well of the intake structure. 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 UHS temperature ensures that the heat-removal capability of the PSW 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

Operating each cooling tower fan for ≥ 15 minutes ensures that all fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration, can be detected for corrective action. The 31-day Frequency was developed considering the known reliability of the fan units, the redundancy available, and the low probability of significant degradation of the cooling tower fans occurring between surveillances. It has also been hown to be acceptable through operating experience.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.5

Verifying the correct alignment for manual, power-operated, and automatic valves in the PSW flow path provides assurance that the proper flow paths will exist for PSW 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 31-day Frequency of this SR was derived from Inservice Inspection and Testing Program requirements for performing valve testing at least one every 92 days. The Frequency was further justified in view of other procedural controls governing valve operation and to provide added assurance of valve correct positions.

SR 3.7.2.6

This surveillance verifies the automatic isolation valves of the PSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety-related equipment during an accident event. This surveillance also verifies the automatic start capability of one of the two PSW pumps in each subsystem.

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.

REFERENCES

1. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," Revision 2, January 1976.

2. [Unit Name] FSAR, Section [4], "[Auxiliary Systems]."

3. [Unit Name] FSAR, Section [6], "[Engineered Safety Features]."

B 3.7 PLANT SYSTEMS

B 3.7.3 Diesel Generator 1B (DG 1B) Standby Service Water (SSW) System (Optional)

BASES

BACKGROUND

The DG 1B SSW System is designed to provide cooling water for the removal of heat from the DG 1B. DG 1B is the only component served by the DG 1B SSW System.

The DG 1B SSW pump auto-starts upon receipt of a diesel generator start signal when power is available to the pump's electrical bus. Cooling water is pumped from the [river] by the DG 1B SSW pump to the essential diesel generator components through the SSW supply header. After removing heat from the components, the water is discharged to the plant service water (PSW) discharge header. The capability exists to manually cross-connect the PSW System to supply cooling to the DG 1B during times when the SSW pump is inoperable. A complete description of the DG 1B SSW System is presented in Reference 1.

APPLICABLE SAFETY ANALYSES

The ability of the DG 1B SSW System to provide adequate cooling to the DG 1B is an implicit assumption for the safety analyses presented in References 2 and 3. The ability to provide onsite emergency AC power is dependent on the ability of the DG 1B SSW System to cool the DG 1B.

The DG 1B SSW System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The OPERABILITY of the DG 1B SSW System is required to provide a coolant source to ensure effective operation of the DG 1B in case of an accident or transient event. The OPERABILITY of the DG 1B SSW System is based on having an OPERABLE pump and an OPERABLE flow path.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the DG 1B SSW pump is bounded by the PSW requirements (LCO 3.7.2).

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(continued)

BASES (continued)

LCO (continued)

[For this facility, the following constitutes an OPERABLE DG 1B SSW System:]

[For this facility, the following support systems must be OPERABLE to ensure DG 1B SSW System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the DG 1B SSW System inoperable and their justification are as follows:]

APPLICABILITY

The requirements for OPERABILITY of the DG 1B SSW System are governed by the required OPERABILITY of the DG 1B (LCO 3.8.1 and LCO 3.8.2).

ACTIONS

A.1 and A.2

If the DG 1B SSW System is inoperable, the OPERABILITY of the DG 1B is affected due to loss of its cooling source; however, the capability exists to provide cooling to the DG 1B Diesel Generator from the PSW System of Unit [1]. Continued operation is allowed for 60 days if the OPERABILITY of the Unit [1] PSW System, with respect to its capability to provide cooling to the DG 1B, can be verified. The 8-hour Completion Time is based on the time required to reasonably complete the Required Action, and the low probability of an event requiring DG 1B occurring during this period. The 31-day verification of the Unit [1] PSW lineup to the DG 1B is consistent with the PSW valve lineup SRs.

The 60-day Completion Time for restoration of the DG 1B SSW System to OPERABLE status allows sufficient time to repair the system, yet prevents indefinite operation with cooling water provided from the Unit [1] PSW System.

The Required Actions have been modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the DG 1B SSW System is inoperable, provided the DG 1B has an adequate cooling water supply from the Unit [1] PSW.

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BASES (continued)

ACTIONS (continued)

B.1

If cooling water cannot be made available to the DG 1B within the 8-hour Completion Time, or if the DG 1B SSW System is not restored to OPERABLE status within 60 days, the DG 1B cannot perform its intended function and must be immediately declared inoperable. The appropriate LCO that requires the DG 1B to be OPERABLE, LCO 3.8.1 or LCO 3.8.2, must be entered.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the DG 1B SSW System flow path provides assurance that the proper flow paths will exist for DG 1B SSW 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. A valve that receives an automatic actuation signal is allowed to be in a non-accident 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 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 of this SR was derived from Inservice Inspection and Testing Program requirements for performing valve testing at least once every 92 days. The Frequency may be further justified in view of other procedural controls governing valve operation, and to provide added assurance of valve correct positions.

SR 3.7.3.2

This SR ensures that the DG 1B SSW System pump will automatically start to provide required cooling to the DG 1B when the DG 1B starts and the respective bus is energized.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Operating experience has shown that these components usually pass the SR when performed on 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. [Unit Name] FSAR, Section [ ], "[Title]."
2. [Unit Name] FSAR, Section [6], "[Engineered Safety Features]."
3. [Unit Name] FSAR, Section [15], "[Accident Analyses]."

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Air Intake, Recirculation, and Purification (AIRP) System

BASES

BACKGROUND

The Control Room AIRP System provides a radiologically controlled environment from which the plant can be safely operated following a Design Basis Accident (DBA).

The safety-related function of AIRP System includes two independent and redundant high efficiency air filtration subsystems. Each subsystem consists of a demister, an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter for emergency treatment of recirculated air or outside supply air, a booster fan, an air-handling unit (excluding the condensing unit), and the associated duct work and dampers. Demisters remove water droplets from the airstream. Prefilters and HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The AIRP System is a standby system, parts of which also operate during normal plant operations to maintain the control room environment. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room personnel), the AIRP System automatically switches to the isolation mode of operation to prevent infiltration of contaminated air into the control room. A system of dampers isolates the control room, and a part of the recirculated air is routed through either of the two filter subsystems. Outside air is taken in at the normal ventilation intake and is mixed with the recirculated air before being passed through one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles.

The air entering the control room is continuously monitored by radiation and toxic gas detectors. One detector output above the setpoint will cause actuation of the emergency radiation mode or toxic gas isolation mode, as required.

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BASES (continued)

BACKGROUND (continued)

The actions of the toxic gas isolation mode are more restricted and will override the actions of the emergency radiation mode.

The AIRP System is designed to maintain the control room environment for 30-days continuous occupancy after a DBA without exceeding 5 rem whole-body dose. A single AIRP subsystem will pressurize the control room to about [0.1] inches water gauge to prevent infiltration of air from surrounding buildings, and provide an air exchange rate in excess of [25]% per hour. AIRP System operation in maintaining the control room habitable is discussed in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The ability of the Control Room AIRP System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in References 3 and 5. The isolation mode of the AIRP System is assumed to operate following a loss-of-coolant accident (LOCA), fuel-handling accident, main steam line break (MSLB), and control rod drop accident (CRDA) (Ref. 1). The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 5. Single-failure criteria are met, since all active components are located in the redundant portions of the system. No single active or passive electrical failure will cause the loss of outside or recirculated air from the control room.

The Control Room AIRP System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two redundant subsystems of the AIRP System are required to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The Control Room AIRP System is considered OPERABLE when the individual components necessary to control operator exposure

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BASES (continued)

LCO (continued)

are OPERABLE in both subsystems. A subsystem is considered OPERABLE when its associated:

a. Fan is OPERABLE;

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

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

d. SRs are met.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

[For this facility, the following support systems must be OPERABLE to ensure Control Room AIRP System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the Control Room AIRP System inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3, the AIRP System must be OPERABLE to control operator exposure during and 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 because of the pressure and temperature limitations in these MODES. During handling of irradiated fuel in the primary or secondary containment, when moving loads over irradiated fuel, during CORE ALTERATIONS operations with a potential for draining the reactor vessel (OPDRVs), the AIRP System must be OPERABLE. Significant radioactive releases can be postulated to occur under these situations, and control room isolation could be required as well.

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BASES (continued)

ACTIONS

A.1

With one AIRP subsystem inoperable, the inoperable AIRP subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE AIRP subsystem is adequate to perform control room radiation protection. The 7-day Completion Time is based on the low probability of a DBA occurring during this time period, and the fact that the remaining subsystem can provide the required capabilities.

The concurrent failure of two AIRP subsystems would result in the loss of functional capability. Therefore, LCO 3.0.3 must be entered immediately.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable AIRP subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE that minimizes risk. This is done by placing the plant 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 MODES from full power in an orderly manner and without challenging plant systems.

C.1

During handling irradiated fuel in the primary or secondary containment, or when moving loads over irradiation fuel, or during CORE ALTERATIONS or OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE AIRP subsystem may be placed in the isolation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any active failure will be readily detected.

Required Action C.1 is modified by a Note to alert the operator to place the system in the toxic gas protection mode if the toxic gas auto-swapover capability is inoperable.

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BASES (continued)

ACTIONS (continued)

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

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactivity that might enter the control room. This places the plant in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or 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 initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and the subsequent potential for fission-product release. Actions must continue until the OPDRVs are suspended.

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

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

During handling of irradiated fuel or other loads in the primary or secondary containment, or during CORE ALTERATIONS or OPDRVs, with two AIRP subsystems inoperable, the Required Action is to immediately suspend activities that present a potential for releasing radioactivity that might enter the control room. This places the plant in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or secondary containment must be immediately suspended. 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 OPDVRs to minimize the probability of a vessel draindown and subsequent potential for fission-product release. Actions must continue until the OPDRVs are suspended.

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BASES (continued)

ACTIONS (continued)

The Required Actions for Condition D are modified by a Note that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that a subsystem in a 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 subsystem once every month provides an adequate check on this system. Monthly heater operation drives out any moisture that has accumulated in the charcoal as a result of humidity in the ambient air. Systems without heaters need only be operated for 15 minutes to demonstrate the function of the system. Furthermore, the 31-day Frequency was developed considering the known reliability of the equipment and the two-subsystem redundancy available.

SR 3.7.4.2

This SR demonstrates the performance of the HEPA and charcoal filters.

The required testing for the AIRP filters is detailed in the Ventilation Filter Testing Program. The program specifies the required tests and their Frequencies. The tests are performed in accordance with Regulatory Guide 1.52 (Ref. 6).

SR 3.7.4.3

The SR demonstrates that on an actual or simulated actuation signal, each AIRP subsystem starts and operates. The 18-month Frequency is specified in Regulatory Guide 1.52 (Ref. 6).

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.4

This SR demonstrates the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure with respect to potentially contaminated adjacent areas (the turbine building) is periodically tested to verify proper function of the AIRP System. During the emergency mode of operation, the AIRP System is designed to slightly pressurize the control room to [0.1] inches water gauge positive pressure with respect to adjacent areas to prevent unfiltered inleakage. The AIRP System is designed to maintain this positive pressure at a flow rate of [400] cfm to the control room in the isolation or pressurization mode. The 18-month Frequency is consistent with the guidance provided in Section 6.4 of NUREG-0800 (Ref. 7).

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [15], "[Accident Analyses]."
4. [Unit Name] FSAR, Section [ ], "[Title]."
5. [Unit Name] FSAR, Section [6], "[Engineered Safety Features]."
6. Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 2, March 1978.
7. NUREG-0800, "Standard Review Plan" Section 6.4, "Control Room Habitability System," Revision 2, July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.5 Control Room Heating, Ventilation, and Air Conditioning (HVAC) System

BASES

BACKGROUND	The Control Room HVAC System provides temperature control for the control room following isolation of the control room. The HVAC System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room air. Each subsystem consists of heating coils, cooling coils, fans, chillers, compressors, ductwork, dampers, instrumentation, and controls to provide for control room temperature control. The HVAC System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem will provide the required temperature control to maintain a suitable control room environment for a sustained occupancy of 12 persons, with temperatures between [70]°F and [85]°F. The HVAC System operation in maintaining the control room temperature is discussed in References 1 and 2.
APPLICABLE SAFETY ANALYSES	The design basis of the Control Room HVAC System is to maintain the control room temperature for 30 days of continuous occupancy. The HVAC System components are arranged in redundant safety-related subsystems. During emergency operation, the HVAC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single failure of a component of the HVAC System, assuming a loss-of-offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The HVAC System is designed in accordance with Seismic Category I requirements. The HVAC System is capable of removing sensible- and latent- heat loads from the control room, which includes consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	The HVAC System satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	Two independent and redundant subsystems of the Control Room HVAC System are required to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding equipment temperature limitations. The HVAC System is considered OPERABLE when the individual components that are necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, associated instrumentation, and controls. In addition, the Control Room Air Intake, Recirculation and Purification System must be OPERABLE to the extent that air circulation can be maintained. [For this facility, the following support systems must be OPERABLE to ensure Control Room HVAC System OPERABILITY:] [For this facility, those required support systems which, upon their failure, do not declare the Control Room HVAC System inoperable and their justification are as follows:]
APPLICABILITY	In MODE 1, 2, or 3, the HVAC System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation. During CORE ALTERATIONS, or when handling irradiated fuel in the primary or secondary containment, or when moving loads over irradiated fuel, or during operations with a potential for draining the reactor vessel (OPDRVs), the HVAC System must be OPERABLE.

(continued)

BASES (continued)

ACTIONS

A.1

If one HVAC subsystem is inoperable, it must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE HVAC subsystem is adequate to perform the control room air conditioning function. The 30-day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and the availability of alternate safety and non-safety cooling methods. [For this facility, the alternate cooling methods are as follows:]

The concurrent failure of two HVAC subsystems would result in the loss of functional capability; therefore, LCO 3.0.3 must be entered immediately.

B.1 and B.2

In MODE 1, 2, or 3, the plant must be placed in a MODE which minimizes the risk if the inoperable HVAC subsystem cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant 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 MODES from full power in an orderly manner and without challenging plant systems.

C.1

During CORE ALTERATIONS, OPDRVs, movement of irradiated fuel in the primary or secondary containment, or movement of loads over irradiated fuel, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE HVAC subsystem should be immediately placed in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures which would prevent automatic actuation will occur, and any active failure would be readily detected.

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BASES (continued)

ACTIONS (continued)

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

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

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or 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 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.

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

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

During CORE ALTERATIONS, OPDRVs, or movement of irradiated fuel or other loads over irradiated fuel in primary or secondary containment, with two HVAC subsystems inoperable, the Required Action is to immediately suspend activities that present a potential for releasing radioactivity which might require isolation of the control room. This places the plant in a condition which minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel or other loads in the primary or 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 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.

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BASES (continued)

ACTIONS (continued)

The Required Actions for Condition D are modified by a Note stating that LCO 3.0.3 is not applicable. If handling fuel while in MODE 1, 2, or 3, the fuel handling is independent of reactor operations. Therefore, inability to suspend handling of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies that the heat-removal capability of the system is sufficient to remove the assumed heat load in the control room. The test is performed at a 18-month Frequency and consists of a combination of testing and calculation. The 18-month Frequency is appropriate since significant degradation of the HVAC System is not expected over this time period.

REFERENCES

1. [Unit Name] FSAR, Section [6.4], "[Title]."
2. [Unit Name] FSAR, Section [9.4.1], "[Title]."

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND	During plant operation, steam from the low-pressure turbine is exhausted directly into the condenser. Air LEAKAGE and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the plant 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 gamma activity flow rate is an initial condition of the offgas system failure event (Ref. 1). The analysis assumes a gross failure in the Offgas System that results in the rupture of the Offgas System pressure boundary. The gross gamma activity flow rate is controlled to ensure that during the event the calculated offsite doses will be well within the limits of 10 CFR 100 or the NRC staff-approved licensing basis. Main Condenser Offgas satisfies Criterion 2 of the NRC Interim Policy Statement.
LCO	To ensure compliance with the assumptions of the offgas system failure event (Ref. 1), the fission-product release rate should be consistent with a noble gas release to the reactor coolant of 100 μCi/MWt-sec at 30-minutes decay. The LCO is established consistent with this requirement (RATED THERMAL POWER (RTP) x 100 μCi/MWt-sec=[ ] mCi/second). (continued)

(continued)

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the 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 flow rate limit is exceeded, a limited time is permitted to restore the gross gamma activity flow rate to within the limit. The 72-hour Completion Time is based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the small probability of an Offgas System rupture.

B.1 and B.2

If the gross gamma activity flow rate is not restored to within the limits in the associated Completion Time of Required Action A.1, all main steam lines or the SJAE must be isolated. This isolates the 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 based on operating experience to perform the action from full power in an orderly manner and without challenging plant 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

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 flow rate. The Frequencies are considered adequate in view of other instrumentation that continuously monitors the offgas, and has been shown to be acceptable through operating experience.

The SR has been modified by a Note which specifies that the SR is required only when any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Offgas System at significant rates. This exception applies to both required Frequencies and allows the frequency "clock" to begin only when the noted condition is met.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

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 plant 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 [25]% of the Nuclear Steam Supply System (NSSS) rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The bypass system consists of a three-valve chest connected to the main steam lines between the main steam isolation valves (MSIVs) and the turbine stop valves. Each of these three valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro-Hydraulic Control (EHC) System (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct 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. 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 [turbine-generator load-rejection transient] (Ref. 2). Opening of the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure that affects the MINIMUM CRITICAL POWER RATIO (MCPR) during the event. An inoperable Main Turbine Bypass System may result in a MCPR penalty. The Main Turbine Bypass System satisfies Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

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, so that the SL MCPR is not exceeded. With the bypass system inoperable, modifications to the MCPR limits (LCO 3.2.2) 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. This response is within the assumptions of the applicable analysis (Ref. 2).

[For this facility, the following constitutes an OPERABLE Main Turbine Bypass System:]

[For this facility, the following support systems must be OPERABLE to ensure Main Turbine Bypass System OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare the Main Turbine Bypass System inoperable and their justification are as follows:]

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RATED THERMAL POWER (RTP) to ensure that the fuel-cladding-integrity safety limit and the cladding 1%-plastic-strain limit are not violated during the [turbine-generator load-rejection transient]. As discussed in the Bases for LCO 3.2.1 and LCO 3.2.2, sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the bypass system is inoperable (one or more bypass valves inoperable), and the MCPR limits for Main Turbine Bypass System are inoperable (as specified in the CORE OPERATING LIMITS REPORT (COLR)), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore

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BASES (continued)

ACTIONS (continued)

the bypass system to OPERABLE status or adjust the MCPR limits accordingly. The 1-hour Completion Time is based on the time required to reasonably complete the Required Action, and the low probability of an event requiring Main Turbine Bypass System action occurring during this period.

B.1

If the bypass system cannot be restored to OPERABLE status or the MCPR limits for the bypass system inoperable are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation below 25% RTP results in sufficient margin to the required limits and the bypass system is not required to protect fuel integrity during the [turbine-generator load-rejection transient]. The 6-hour Completion Time is based on operating experience related to the time required to reach the reduced power level from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Cycling the bypass valves through one complete cycle of full travel, demonstrates that the valves are mechanically OPERABLE and will function when required. The 31-day Frequency of this SR was derived from the Inservice Inspection and Testing Program requirements for performing valve testing at least once every 92 days. Operating experience has shown that these components usually pass the SR when performed on the 31-day Frequency. Therefore, the Frequency is concluded to be acceptable from a reliability standpoint.

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 was developed considering the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

reactor at power. Operating experience has shown the 18-month Frequency, which is based on the refueling cycle, to be acceptable from a reliability standpoint.

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 [plant-specific documentation]. The 18-month Frequency was developed considering the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the SR is performed with the reactor at power. Operating experience has shown the 18-month Frequency to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.7 PLANT SYSTEMS

B 3.7.8 Spent Fuel Storage 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. The specified water level also shields and minimizes the general-area dose when the storage racks are at their maximum capacity and provides shielding during the movement of spent fuel. A general description of the spent fuel storage pool design is found in Reference 1. The assumptions of the fuel-handling accident are found in Reference 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% of 10 CFR 100 exposure guidelines (Ref. 3). A fuel-handling accident could release a fraction of the fission-product inventory by breaching the fuel-rod cladding (Ref. 4). The fuel-handling accident of Reference 1 is evaluated for the dropping of an irradiated fuel assembly onto the reactor core. The consequences of a fuel-handling accident over the spent fuel storage pool are no more severe than those of the fuel-handling accident over the reactor core (Ref. 1). 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 secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel-handling accident. Spent fuel storage pool water level satisfies Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

The specified water level preserves the assumptions of the fuel-handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.

[For this facility, the following constitutes an OPERABLE spent fuel storage pool water level:]

[For this facility, the following support systems are required to be OPERABLE to ensure spent fuel storage pool water level OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the spent fuel storage pool water level inoperable and their justification are as follows:]

APPLICABILITY

This LCO applies whenever irradiated fuel is in the spent fuel storage pool because the potential for a release of fission products exists.

ACTIONS

A.1

When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the handling of irradiated fuel assemblies in the spent fuel storage pool is immediately suspended. 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. Plant procedures control the movement of loads over the spent fuel in all cases.

A.2

Action must be initiated immediately to restore the water level. Actions must continue until water level is restored to within limits.

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BASES (continued)

ACTIONS (continued)

Required Actions A.1 and A.2 are modified by a Note that allows an exemption from LCO 3.0.3 and LCO 3.0.4. These LCOs are not applicable as events in the spent fuel storage pool are not affected by MODE level or facility operations.

In the event that the required spent fuel storage pool water level is found inoperable, the spent fuel storage pool water level is considered to be not within limits and Required Action A.1 and Required Action A.2 apply.

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 appropriate, considering that the volume in the pool is normally stable, water level changes are controlled by plant procedures, and it has been proven to be acceptable through operating experience.

During refueling operations, the level in the fuel pool is in equilibrium with that of the refueling canal, and the level in the refueling canal is checked daily under SR 3.9.6.1.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

2. [Unit Name] FSAR, Section [ ], "[Title]."

3. NUREG-0800, "Standard Review Plan," Section 15.7.4, "Radiological Consequences of Fuel Handling Accidents," Revision 1, July 1981.

4. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors," March 1972.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

Introduction

The [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} AC source consist of the offsite power sources [preferred power sources, normal and alternate(s)], and the onsite standby power sources [[Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} diesel generators]. As required by 10 CFR 50, Appendix A, GDC 17, "Electric Power Systems" (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.

{VS-BW,CE,W,BWR/4: The onsite Class 1E AC Distribution System supplies electrical power to [two redundant divisional load groups], with each [division] powered by [an independent Class 1E 4.16 kV ESF bus]. [Each [ESF bus] has at least [one] separate and independent offsite source[s] of power as well as a dedicated onsite diesel generator source.] The [Division 1 and Division 2] ESF systems each provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition. [An electrical power distribution system diagram is provided in Figure B 3.8.1-1.]}

{VS-BWR/6: The onsite Class 1E AC Distribution System supplies electrical power to [three divisional load groups], with each [division] powered by an [independent Class 1E 4.16 kV ESF bus]. The [Division 1 and 2] [ESF buses] each have at least [one] separate and independent offsite source[s] of power. The [Division 3] [ESF bus] has at least [one] offsite source[s] of power. Each [ESF bus] has a dedicated onsite diesel generator. 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. [An electrical power distribution system diagram is provided in Figure B.3.8.1-1.]}

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BASES (continued)

"This Figure For Illustration Only. Do Not Use For Operation"

[PLANT SPECIFIC FIGURE]

[inclusion optional]

Figure B 3.8.1-1 (Page 1 of 1)
Electrical Power System

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BASES (continued)

BACKGROUND (continued)

The redundant parts of the AC electrical power system are electrically, physically, and functionally independent to the extent that no single failure will cause a total loss of power to redundant safety-related load groups.

A single failure is an occurrence that results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Electrical systems are considered to be designed against an assumed single failure if neither a single failure of any active component (assuming passive components function properly) nor a single failure of a passive component (assuming active components function properly) results in a loss of the capability of the system to perform its safety functions.

In the event of a loss of preferred power, the ESF switchgears are automatically connected to the diesel generators in sufficient time for safe reactor shutdown or in sufficient time to mitigate the consequences of a Design Basis Accident (DBA) such as a loss-of-coolant accident (LOCA).

Offsite Sources

Offsite power is supplied to the [plant name] [switchyard(s)] from the transmission network by [two] transmission lines, which come into [the switchyard(s) via [two] right-of-way(s)]. From the [switchyard(s)] [two] electrically and physically separated circuits provide AC power, through [step-down station auxiliary transformers], to the [4.16 kV ESF buses]. The [two] offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the [onsite Class 1E ESF bus or buses].

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BASES (continued)

BACKGROUND (continued)

[PLANT SPECIFIC:
Provide description of any other salient features of the offsite power sources. Items that may be covered include:

a. Circuit breakers and protective relaying;

b. Ability to cross tie offsite circuits so that one circuit may power both ESF buses;

c. Normal at-power and shutdown electrical alignments;

d. Offsite circuit capability;

e. Ability to power ESF buses from the plant's own generator output via the unit auxiliary transformers; and

f. A description, for both the at-power and shutdown lineups, of alternate power availability from alternate offsite power circuits. Include in the description the capability of the alternate circuits, and whether the circuit is immediate or delayed access. If it is a delayed access circuit, describe what has to be done to gain access to the circuit (such as remove generator disconnect links) and whether the actions can be done remotely from the control room. Also state the amount of time required to perform the actions.

g. Discuss whether the sequencer is a support system for the offsite circuits, and whether the circuits are block-loaded with ESF loads, or whether they have the loads sequenced onto them.

h. Define and discuss the physical and functional characteristics of the offsite circuits that make them "separate and independent." Also, "separate" should be defined in terms of firedoors not closed, etc.]

Onsite Sources

The onsite standby power source for each [4.16 kV ESF bus] is a dedicated diesel generator. {VS-BW,CE,W,BWR/4: [Diesel generators (DGs) [11] and [12] are dedicated to ESF buses

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BASES (continued)

BACKGROUND (continued)

[11] and [12], respectively].} {VS-BWR/6: [Diesel (DGs) generators [11], [12], and [13] are dedicated to ESF buses [11], [12], and [13], respectively].} A DG starts automatically on {VS-BW,CE,W: [a safety injection signal (SIS) (i.e., low pressurizer pressure or high containment pressure signals)]} {VS-GE:[a LOCA signal (i.e., low reactor water level signal or high drywell pressure signal)]} or on an [ESF bus degraded voltage or undervoltage signal]. The undervoltage trip device senses a severe loss-of-voltage to a level at which electrical equipment would not function. The degraded voltage trip device senses a loss of voltage condition at which the equipment would function, but would sustain damage and become inoperable if operated for extended periods with degraded voltage. Additionally, after the diesel generator has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of [ESF bus] undervoltage or degraded voltage, independent of or coincident with a safety injection signal. The DGs will also start and operate in the standby mode without tieing to the [ESF bus] on a safety injection signal alone. Following the trip of offsite power, a sequencer strips all non-permanent loads from the [ESF bus]. When the DG is tied to the [ESF bus], loads are then sequentially connected to their respective [ESF bus] by their automatic sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent an overburdened DG by automatic load application.

Ratings for [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} DGs satisfy the requirements of Regulatory Guide 1.9, "Selection, Design, and Qualification of DG Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (Ref. 2). The continuous service rating of each of the DGs is [7,000] kW for [Divisions 1 and 2] {VS-BWR/6: and is [3,000] kW for [Division 3]} with [10]% overload permissible for up to 2 hours in any [24]-hour period. The ESF loads that are powered from the [4.16 kV ESF buses] are listed in Reference 3.

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BASES (continued)

BACKGROUND (continued)

Automatic Sequencers

The sequencer(s) is (are) activated by one of two conditions, [ESF bus] undervoltage (UV) or {VS-BW,CE,W: SIS} {VS-GE: LOCA signal}. Upon receipt of either or both of the initiating signals, the following actions will take place:

a. The DGs start;

b. Any test sequence in progress stops;

c. The [ESF bus] of all non-permanent loads (UV only) is stripped;

d. The DG breaker (UV only) closes; and

e. The appropriate loads as determined by the initiating signal energize.

Required plant loads are returned to service in a sequence determined to ensure that the most essential loads are started first while preventing overloading of the DGs in the process. Within [1 minute] after the initiating signal is received, all loads needed to recover the plant or maintain it in a safe condition are returned to service.

The sequencer is an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus.] Therefore, loss of an [ESF bus's sequencer] affects every major ESF system in the [division].

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in the FSAR, [Chapter 6, "Engineering Safety Features"], and [Chapter 15, "Accident Analyses"], assume 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

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

detail in the Bases for Technical Specifications (TS) 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (containment systems).

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite or offsite AC sources, DC power sources and associated distribution systems 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 NRC Interim Policy Statement.

LCO

As a minimum, the following AC electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E Distribution System {VS-BWR/6: and a third [Division 3] circuit, not necessarily separate and independent from the first two}; and

b. {VS-BW,CE,W,BWR/4: Two} {VS-BWR/6: Three} separate and independent DGs {VS-BW,CE,W,BWR/4: [11] and [12]} {VS-BWR/6: [11], [12, and [13]}, each with:

   1. separate day [and engine-mounted] fuel tanks containing a minimum volume of fuel within the limits specified in SR 3.8.1.8,

   2. a separate Fuel Storage System containing a minimum volume of fuel within the limits specified in SR 3.8.1.9,

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BASES (continued)

LCO (continued)

3. a separate fuel transfer pump capable of meeting SR 3.8.1.16,

4. lubricating oil storage containing a minimum total volume of lubricating oil within the limits specified in SR 3.8.1.10,

5. capability to transfer lubricating oil from storage to the DG unit, and

6. separate air-start receivers containing a minimum air pressure within the limits of SR 3.8.1.7.

In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE. {VS-BWR/6: [PLANT SPECIFIC: In general, [Division 3] does not have a load sequencer since it has only one large load, i.e., high pressure core spray (HPCS) pump. In such cases the LCO should refer to the [Division 1 and 2] sequencers only.]}

For the offsite circuits, DGs, and sequencers to be OPERABLE, they must be capable of performing their intended function, have all support systems OPERABLE, and have successfully completed all SRs.

[Each facility will define what constitutes an OPERABLE offsite circuit, including the components of the circuit, such as breakers, transformers, switches, interrupting devices, protective relays, cabling and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF buses.]

[For this facility, as a minimum, the following support systems are required OPERABLE to assure offsite circuit OPERABILITY:]

[ ]

Inoperability of any of the offsite circuit support systems results immediately in an inoperable offsite circuit as per the definition of OPERABILITY; however, exceptions are

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BASES (continued)

LCO (continued)

allowed for specific support systems, provided that a justification is given. Therefore, upon the inoperability of the following support systems for an offsite circuit, the declaration of an inoperable offsite circuit may be delayed:

[ ]

The justification for delaying the declaration of offsite circuit inoperability for each of the above items is as follows:

[ ]

[Each facility will define what constitutes an OPERABLE DG, including the components of the DG, such as the diesel engine, generator, Fuel Storage System, starting and control air, combustion air intake and exhaust, cooling system, lubricating oil, ventilation, and DG output breaker.]

[For this facility, as a minimum, the following support systems are required OPERABLE to assure DG OPERABILITY:]

[ ]

Inoperability of any of the DG support systems results immediately in an inoperable DG as per the definition of OPERABILITY; however, exceptions are allowed for specific support systems provided that a justification is given. Therefore, upon the inoperability of the following support systems for a DG, the declaration of an inoperable DG may be delayed:

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(continued)

BASES (continued)

LCO (continued)

[ ]

The justification for delaying the declaration of DG inoperability for each of the above items is as follows:

[ ]

[Each facility will define what constitutes an OPERABLE [automatic sequencer, including the components of the sequencer such as programmable logic arrays].

[For this facility, as a minimum, the following support systems are required OPERABLE to assure [automatic sequencer] OPERABILITY:]

[ ]

Inoperability of any of the [automatic sequencer] support systems results immediately in an inoperable [automatic sequencer] as per the definition of OPERABILITY; however, exceptions are allowed for specific support systems provided that a justification is given.

Therefore, upon the inoperability of the following support systems for an [automatic sequencer], the declaration of an inoperable [automatic sequencer] may be delayed:

[ ]

(continued)

(continued)

BASES (continued)

LCO (continued)

The justification for delaying the declaration of [automatic sequencer] inoperability for each of the above items is as follows:

[ ]

AC Sources and Component OPERABILITY

The definition of OPERABILITY states that a component shall be OPERABLE when it is capable of performing its specified functions and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the component to perform its functions are also capable of performing their related support functions. When applying this definition to a component, say an Emergency Core Cooling System (ECCS) pump, the question arises, "How many AC sources are necessary for the pump to be considered OPERABLE?" For the electrical power distribution buses to be OPERABLE, they simply have to be fully energized by one of the capable sources accepted in the plant design, within design voltage and frequency tolerances, and within allowable environmental parameters such as temperature and humidity. Similarly, an ECCS pump is OPERABLE if it is powered from such a fully energized and OPERABLE distribution system. Note that for OPERABILITY of both the distribution system and the components, no requirements, beyond at least one of the electrical power sources that was accepted as a part of the plant design, are made on how many electrical power sources are available to power the bus.

Thus, for plant components and distribution buses, zero electrical power sources means the component or bus is inoperable. Fully energized from at least one power source that was accepted as a part of the plant design means the component or bus is OPERABLE (at least from the point of view of needing electrical support). Thus, the principle for component (including electrical bus) OPERABILITY is that a component may be considered OPERABLE if it has electricity at its terminals (and the electricity came from a source that was accepted as a part of the plant design).

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BASES (continued)

LCO (continued)

With this interpretation of component OPERABILITY, the next question that arises is, "How can an ECCS pump that is only powered from an offsite source be considered OPERABLE?" If such a pump does not have electrical support from a DG, it will not be able to function given a DBA and a loss of offsite power. The short answer to this question is that it is not the ECCS pump that was broken in the above scenario. It was a DG that was inoperable. Thus, for operating MODES, this LCO 3.8.1 contains the necessary ACTIONS for an inoperable required AC source (including a DG). Similarly, for shutdown modes, LCO 3.8.2 contains the necessary ACTIONS for an inoperable required AC source under shutdown conditions. Cascading the inoperability of a single AC source (including DG) to every component in the [division] served by the AC source is not necessary. The longer answer to this question requires some additional explanation.

The electrical power systems at nuclear power plants are designed to meet the GDC listed in Appendix A of 10 CFR 50. The AC electrical power system is designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. The OPERABILITY of the power sources are based upon meeting the design basis of the plant. This includes maintaining at least:

a. {VS-BW,CE,W,BWR/4: One [division] ([Division 1 or Division 2])} {VS-BWR/6: Two out of three [divisions]} of the offsite AC and onsite DC power sources and associated distribution systems OPERABLE during accident conditions, assuming a loss of all onsite power and a single failure; and

b. {VS-BW,CE,W,BWR/4: One [division] ([Division 1 or Division 2])} {VS-BWR/6: Two out of three [divisions]} of the onsite AC and DC power sources and associated distribution systems OPERABLE during accident conditions, assuming a loss of all offsite power and a single failure.

See, for example, GDC 17, 33, 34, 35, 38, and 41.

An important corollary to or consequence of the design requirements (a) and (b) above is the following. For a

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BASES (continued)

LCO (continued)

safety-related component to be considered operable, it must have both a source of offsite and onsite power. This is the design basis definition that is shown here in lower case letters and underlined to distinguish it from the actual definition of OPERABLE that is used in the Technical Specifications. This definition of operable is every bit as valid as the design criteria for a nuclear plant. The difference is that a component is OPERABLE if it has at least one AC source; however, it may not be operable. To be operable, the component would have to have both an onsite and offsite AC source.

Let's examine the differences between OPERABLE and operable for the operating MODES of Applicability that are governed by Specification 3.8.1 (and other operating Technical Specifications). For a typical plant, the LCO of Specification 3.8.1 requires a DG and an offsite circuit for each [division]. Thus, as long as the LCO of Specification 3.8.1 is met, all components are both OPERABLE and operable (in terms of the electrical support they require). Furthermore, if three or more AC sources are inoperable, then the plant must enter LCO 3.0.3 and shut down. Therefore, in these two extremes, any difference between OPERABLE and operable becomes irrelevant. If two AC sources are inoperable on the same bus, and if that bus has no other source of power (e.g., a dead bus), then the two definitions also give the same result, and every component in the [division] is inoperable since they have no electrical power. In fact, the only time the difference becomes relevant is when one or two (but with no dead bus) AC sources become inoperable.

Thus, when in the ACTIONS of Specification 3.8.1 for one or two AC sources inoperable, the components in the [divisions] associated with the inoperable AC source(s) are generally OPERABLE but not operable. At this point, the reason for defining OPERABILITY as requiring only one AC source becomes clear. If one uses the design basis definition of operability in place of OPERABILITY, then every component in the [division] would have to be declared not operable upon the loss of a single AC source.

Performing the Required Actions of the TS for each component that requires AC power in a [division] (when the components still have AC power) just because one AC source is

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BASES (continued)

LCO (continued)

inoperable is not necessary. Fix the AC source and leave the components alone.

If we use the definition of <u>operability</u>, then upon the loss of two AC sources in different [divisions] the plant would have to enter LCO 3.0.3 since two entire safety [divisions] of components would be not <u>operable</u>. This would make the 2-, 12-, and 24-hour Completion Times specified in LCO 3.8.1 for two DGs inoperable, one DG and one offsite circuit inoperable, and two offsite circuits inoperable, respectively, irrelevant.

By not cascading the inoperability of a single AC source down to all the components in its safety [division], two things are lost:

a. The Required Actions for an inoperable component in the component LCO; and

b. A message to the component LCO that the component in this [division] is potentially inoperable under certain Design Basis Events.

The loss of (a) is probably not important. Usually, the Required Action is simply to restore the component to OPERABLE status. In this case, it is not the component that is broken, it is the AC source. The AC source will be fixed within its Completion Time, or other remedial actions, such as a plant shutdown, will be taken.

The loss of (b) *is* important. Most component LCOs do not allow continued plant operation with a complete loss of function. For example, a typical ECCS Specification will allow loss of ECCS function in one [division] for 72 hours but will require a shutdown if all ECCS function is lost. It is clear that if the design basis definition of <u>operability</u> was used, and if a DG in one [division] was out of service coincident with an ECCS pump in another [division], a shutdown would be required by the ECCS Specification since two ECCS pumps would be not <u>operable</u>. However, when the Specification definition of OPERABILITY is used in place of <u>operability</u>, the ECCS Specification shows one pump inoperable with a 72-hour Completion Time, and the AC sources TS would have one DG inoperable with a 72-hour

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BASES (continued)

LCO (continued)

Completion Time. Thus, there appears to be a difficulty if an AC source is out of service in one [division], and a required feature (such as an ECCS pump) is out of service in another [division].

The problem is that this situation (AC source inoperable in one [division], required feature inoperable in another) represents a potential loss of required feature function under some of the conditions set forth in the design basis. By using the TS definition of OPERABILITY, no message is sent to the required feature LCO upon the inoperability of an AC source. To fix this problem, a cross-[division] check is incorporated into this LCO 3.8.1. See Condition B (for offsite source inoperability) and see Condition D (for onsite source inoperability). The purpose of these two conditions is to recognize that when in them, the plant is in a potential loss-of-function situation. The effect of these two Conditions is to reduce the Completion Time for an inoperable AC source to less than 72 hours. See the appropriate ACTIONS discussion for more information.

Another point of view is that, in practice, the design basis requirement for <u>operability</u> is relaxed for brief periods of time (typically 72 hours or less) while in an AC Sources—Operating ACTION statement. If a [Division 1] DG is out of service, all of the components in the safety [division] associated with that DG are not declared inoperable (even though by the strict definition of <u>operability</u> above, they are, in fact, not <u>operable</u>). Instead, the definition of <u>operability</u> is relaxed to that of OPERABILITY, which says that if a component in the [division] that has an out-of-service DG has electricity at its terminals, it is OPERABLE for the purpose of satisfying its component LCO. Thus, the only ACTION that has to be taken is that of the DG LCO. This relaxation of the design basis definition of <u>operability</u> is deemed acceptable because the DG inoperability is only allowed to persist for a limited amount of time (e.g., 72 hours in this case). The net effect of this interpretation is that during the 72 hours, the GDC are not met. The plant could not take a worst-case single failure and still maintain all safety functions with a loss of all offsite AC sources. In other words, we accept the risk of loss of single-failure protection for an event that involves total loss of offsite AC sources for 72 hours.

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BASES (continued)

LCO (continued)

The above discussion holds equally well for the companion Condition of one offsite circuit inoperable (instead of a DG). Thus, the requirement for both an onsite and offsite AC source of power found in the definition of operability is relaxed for 72 hours while in the AC Sources—Operating ACTION statement for one offsite circuit inoperable.

This relaxation of a design basis requirement is only implemented when in an ACTION of Specification 3.8.1. At all other times, the correct design basis interpretation of the "Necessary electrical power" in the definition of operability is that both onsite and offsite AC sources are required for a component to be considered operable and thus meet the design basis requirements.

Separation and Independence of AC Sources

An additional corollary to or consequence of the design requirements in GDC 17 is that the AC sources in one [division] must be separate and independent (to the extent possible) of the AC sources in the other [division(s)]. For the onsite diesel generators, the separation and independence is complete. That is, GDC 17 requires,

> "The onsite electric power supplies, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, for redundancy, and testability to perform their safety functions assuming a single failure."

For the offsite AC sources, the separation and independence is to the extent practical. That is, GDC 17 requires,

> "Electric power from the transmission network to the onsite electrical distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions."

It is not acceptable to extrapolate from these words in GDC 17 that the offsite circuits are not completely separate and independent and conclude therefore that a single circuit

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BASES (continued)

LCO (continued)

cross-tied between [divisions] meets the GDC 17 requirements for offsite sources. Similarly, if interrupting devices or protective relaying that normally serves to provide electrical independence between the two circuits are inoperable, it is not acceptable to conclude that all offsite circuits are still OPERABLE. In general, the two offsite circuits are to be maintained separate and independent to the same extent as in the plant design.

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: 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 anticipated operational occurrences (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.

AC power requirements for {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in Specification 3.8.2, "AC Sources—Shutdown."

A Note has been added to provide clarification that for this LCO, all required [Division 1] {VS-BW,CE,W,BWR/4: and [Division 2]} {VS-BWR/6: , [Division 2], and [Division 3]} AC electrical sources and [automatic sequencers] shall be treated as an entity with a single Completion Time.

ACTIONS

A.1

Condition A is one required offsite circuit inoperable. The Required Action A.1 is to restore all required AC electrical power sources (offsite circuits and DGs) to OPERABLE status within a Completion Time of 72 hours {VS-BWR/6: for [Division 1 and Division 2] and within [72 hours] for [Division 3]}.

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BASES (continued)

ACTIONS (continued)

Performance of SR 3.8.1.1 ensures a highly reliable power source and no common cause failure for the remaining required offsite {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits}. The OPERABILITY of the remaining required offsite {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits} must be verified once within 1 hour and once per 8 hours thereafter until the inoperable offsite circuit is restored to OPERABLE status.

SR 3.8.1.1 is only required when in Condition A. SR 3.8.1.1 is essentially identical to the normal weekly SR of offsite circuits (i.e., SR 3.8.1.4). The only difference is that SR 3.8.1.1 has a shorter Frequency for verification of the OPERABILITY of the remaining required OPERABLE offsite circuit. If a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition F, for two offsite circuits inoperable, is entered.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition A for a period that should not exceed 72 hours {VS-BWR/6: for [Divisions 1 and 2]. The [72-hour] Completion Time for a [Division 3] offsite circuit inoperability is plant specific. Items to be considered in choosing this Completion Time are:

a. Potential light-loading of the [Division 3] DG during the [72-hour] period when the one required offsite circuit for [Division 3] is inoperable; and

b. The safety function of [Division 3].

In particular, the Completion Time for a [Division 3] offsite circuit inoperability shall not exceed 72 hours if [Division 3] systems support other ESF functions in addition to the HPCS function}. With one offsite circuit inoperable, 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 this Condition, however, the remaining OPERABLE offsite {VS-BW,CE,W,BWR/4: circuit} {VS-BWR/6: circuits} and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

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BASES (continued)

ACTIONS (continued)

The 72-hour {VS-BWR/6: (or 72-hour] for [Division 3])} limit 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. If Required Action A.1 and its associated Completion Time are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

{VS-BW,CE,W: B.1, B.2.1, and B.2.2}
{VS-GE: B.1, and B.2}

{VS-BW,CE,W:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power, or with opposite OPERABLE DC power subsystem(s), or both, OR the turbine-driven auxiliary feedwater pump inoperable.

{VS-W,CE,W:
Note that the OR in Condition B is not an exclusive "or". That is, the OR in Condition B includes Conditions in which:

a. One or more required support or supported features, or both, are inoperable. . .; or

b. A Condition in which the turbine-driven auxiliary feedwater pump is inoperable; or

c. Both (a) and (b) above.}

{VS-BWR/4:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power, or with opposite OPERABLE DC power subsystem(s), or both.}

{VS-BWR/6:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System AND one or more required support or supported features, or both, inoperable that are associated with the other [divisions] that have

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BASES (continued)

ACTIONS (continued)

offsite power, or associated with opposite OPERABLE DC power subsystem(s), or both.}

Condition B is a companion Condition to Condition A. That is, it is not possible to be in Condition B without also being in Condition A. [For there to be no offsite power to one [division] of the onsite Class 1E Distribution System, one offsite circuit and any cross-ties to other offsite circuits must be inoperable or not connected.]

The rationale behind Condition B comes from GDC 33, 34, 35, 38, and 41. They state that,

> "Suitable redundancy in components and features, and suitable interconnections, leakage detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure."

If, as per the GDC, we assume that all onsite power is not available, then Condition B represents a loss of function for the feature that is inoperable in the other {VS-BW,CE,W,BWR/4: [division] that has} {VS-BWR/6: [divisions] that have} offsite power, or is associated with opposite OPERABLE DC power subsystem(s), or both.

Definition of BX: The allowable time for continued plant operation in Condition B is BX hours. BX is determined as follows. Consult the TS for the required feature that is inoperable. Define BXi as the Completion Time that the inoperable required feature TS allows for a complete loss of all required feature function. If no loss of function is allowed (e.g., if upon the loss of required feature function a shutdown is required), then assign BXi = 0 hours. For each required feature that is inoperable, there will be a BXi. BX is then defined as the minimum of all the BXi; however, if BX is found to be less than 24 hours, BX is reset to 24 hours. If BX is found to be greater than 72 hours, then BX is 72 hours.

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BASES (continued)

ACTIONS (continued)

There is one exception to the above rule for finding BX. Usually, 24 hours ≤ BX ≤ 72 hours. However, if the plant is in Condition B and Condition F (two required offsite circuits inoperable) simultaneously, then BX = 12 hours. The rationale for the reduction to 12 hours is that Condition F (two required offsite circuits inoperable) is assigned a Completion Time of 24 hours consistent with Regulatory Guide 1.93 (Ref 4.). However, on a risk basis, Regulatory Guide 1.93 allowed a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety [divisions] of components are OPERABLE. When in Condition B and F simultaneously, this is not the case, and a shorter Completion Time of BX = 12 hours is appropriate.

BX as defined above is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown. (The above addresses the potential for loss of function under certain Conditions postulated in the design basis. In the event of an actual loss of function, the TS covering that loss of function will control the Completion Time.)

The specific list of "required support and supported features" encompassed by Condition B is provided in Reference 5. Required features are those that are designed with functionally redundant safety-related [divisions]. If a plant has a required feature that has no functionally redundant counterpart, that feature may not be required to be included. This is unlikely, however, since single-failure considerations usually require functional redundancy of safety features. Since the Completion Time allowance for this Required Action is limited to 72 hours, those systems with allowed Completion Times ≥ 72 hours for complete loss of function are not included as required features to be checked.

The reason that Condition B is for no offsite power to one [division] of the onsite Class 1E Distribution System is because losing one offsite circuit may not necessarily result in the total loss of offsite power to the [division] because of possible cross-ties to other offsite circuits. No offsite power source to one [division] needs to be established before the determination can be made whether an

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BASES (continued)

ACTIONS (continued)

inoperable redundant feature in the other [divisions] would result in a potential loss of function.

{VS-BW,CE,W:
Auxiliary feedwater is provided by a [50%]-capacity motor-driven feedwater pump in [Division 1], a [50%]-capacity motor-driven feedwater pump in [Division 2], and a [100%]-capacity turbine-driven feedwater pump. Therefore, assuming that all onsite power is not available (as per the GDC), Condition B reduces the 72-hour Completion Time to BX hours (see above for definition of BX) for the case in which auxiliary feedwater function has been reduced to only [50%] of capacity or less.}

{VS-BW,CE,W:
The turbine-driven auxiliary feedwater pump is not included with the "one or more required support or supported features, or both, inoperable that are associated with the other [division] that has offsite power," because the feedwater pump is steam driven (as opposed to motor driven), and thus is not "associated" with either [division] of the AC electrical power sources.}

{VS-BW,CE,W:
The Note for Required Action B.2.2 states, "Required Action B.2.2 is only required in MODES 1, 2, and 3, and in MODE 4 when auxiliary feedwater is being used for plant shutdown and startup." This Note is consistent with the Applicability requirements of Specification 3.7.4, "Auxiliary Feedwater System." When the pressure is < 715 psig] the turbine-driven auxiliary feedwater pump need not be capable of meeting the SR limits of SR 3.7.4.2 on developed head to satisfy the OPERABILITY requirements of Required Action B.2.2. The pump must be capable of coming up to speed and delivering flow, however. Furthermore, the licensee shall verify that the pump passed its last SR 3.7.4.2.}

Operation may continue in Condition B for a period that should not exceed BX hours. In this condition, the remaining OPERABLE offsite circuit and DGs are adequate to

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BASES (continued)

ACTIONS (continued)

supply electrical power to [Division 1 and Division 2] of the onsite Class 1E Distribution System. The BX-hour limit takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Thus, on a component basis, we may have lost single-failure protection for the required feature's function; however, we have not lost function. Similarly, we take 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. If the Required Actions of Condition B and the associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

C.1

Condition C is one required DG inoperable. Required Action C.1 is to restore the required AC electrical power sources (offsite circuits and DGs) to OPERABLE status within a Completion Time of 72 hours
{VS-BWR/6: for [Division 1 and Division 2] and within [72 hours] for [Division 3]}.

Performance of SR 3.8.1.2 ensures a highly reliable power supply by checking on the OPERABILITY of the required offsite circuits. SR 3.8.1.2 must be performed once within 1 hour of entering Condition C, and once per 8 hours thereafter. Failing to perform SR 3.8.1.2 on a given circuit results in an inoperable circuit. Similarly, if a circuit fails to pass SR 3.8.1.2, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered to reflect the new plant state.

Performance of SR 3.8.1.3 ensures no common cause failure for the remaining required DG[s]. The determination of no common cause inoperability of the remaining required DG[s] must be made once within [8] hours of entering Condition C. If during the performance of SR 3.8.1.3 common cause is found, or if a required DG fails SR 3.8.1.3 for some other reason, then two required DGs are inoperable and Condition G is entered.

Note 3 of Condition C requires that SR 3.8.1.3 shall be completed if Condition C is entered. The intent is that all DG inoperabilities must be investigated for common cause

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BASES (continued)

ACTIONS (continued)

failures as per SR 3.8.1.3, regardless of how long the DG inoperability persists.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition C for a period that should not exceed 72 hours {VS-BWR/6: for [Divisions 1 and 2]. The [72-hour] Completion Time for a [Division 3] DG inoperability is based upon the risk-significance of the [Division 3] DG in coping with a station blackout (SBO). Calculations show that the core melt frequency increases substantially for an SBO with a [Division 3] DG inoperable for 14 days as compared to an SBO with an OPERABLE [Division 3] DG.

The Completion Time for a [Division 3] DG may be increased from [72 hours] to [14 days] consistent with the HPCS TS provided:

a. The [Division 3] sole function is to support the HPCS function; and

b. Calculations show that the increase in the core melt frequency for an SBO with an inoperable [Division 3] DG is acceptably low.

If other ESF functions are supported by [Division 3], or if calculations show that the increase in core melt frequency for an SBO with an inoperable [Division 3] DG is unacceptably high, then the Completion Time for an inoperable [Division 3] DG shall be [72 hours].}

In Condition C, the remaining OPERABLE DG[s] and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72-hour {VS-BWR/6: (or [72-hour] for [Division 3])} limit 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. If Required Action C.1 and its associated Completion Time are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

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BASES (continued)

ACTIONS (continued)

{VS-BW,CE,W: D.1, D.2.1, and D.2.2}
{VS-GE: D.1 and D.2}

{VS-BW,CE,W:
Condition D is one required DG inoperable AND one or more required support or supported features, or both, inoperable that are associated with the OPERABLE DG[s], or with an opposite OPERABLE DC power subsystem, or both, OR the turbine-driven auxiliary feedwater pump inoperable.

{VS-BW,CE,W:
Note that the OR in Condition D is not an exclusive "or". That is, the OR in Condition D includes Conditions in which:

a. One or more required support or supported features, or both, are inoperable. . .; or

b. A Condition in which the turbine-driven auxiliary feedwater pump is inoperable; or

c. Both (a) and (b) above.}

{VS-BWR/4:
Condition D is one required DG inoperable AND one or more required support or supported features, or both, inoperable that are associated with the OPERABLE DGs, or with an opposite OPERABLE DC power subsystem, or both.}

{VS-BWR/6:
Condition D is one DG inoperable AND one or more required support or supported features, or both, inoperable that are associated the OPERABLE DGs, or with opposite OPERABLE DC power subsystems, or both.}

Condition D is a companion Condition to Condition C. That is, it is not possible to be in Condition D without also being in Condition C.

The rationale behind Condition D comes from GDC 33, 34, 35, 38, and 41. They state that,

> "Suitable redundancy in components and features, and suitable interconnections, leakage detection, isolation, and containment capabilities shall be

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BASES (continued)

ACTIONS (continued)

provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure."

If, as per the GDC, we assume that all offsite power is not available, then Condition D represents a loss of function for the feature that is inoperable in the other {VS-BW,CE,W,BWR/4: [division] that has an OPERABLE DG or in the opposite OPERABLE DC power subsystem, or both.} {VS-BWR/6: [divisions] that have OPERABLE DGs or in opposite OPERABLE DC power subsystems, or both.}

Definition of DX: The allowable time for continued plant operation in Condition D is DX hours. DX is determined as follows. Consult the TS for the required feature that is inoperable. Define DXi as the Completion Time that the inoperable required feature TS allows for a complete loss of all required feature function. If no loss of function is allowed (e.g., if upon the loss of required feature function a shutdown is required), then assign DXi = 0 hours.

For each required feature that is inoperable, there will be a DXi. DX is then defined as the minimum of all the DXi; however, if DX is found to be less than 2 hours, DX is reset to 2 hours. If DX is found to be greater than 72 hours, then DX is 72 hours.

DX as defined above is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown. (The above addresses the potential for loss of function under certain Conditions postulated in the design basis. In the event of an actual loss of function, the TS covering that loss of function will control the Completion Time.)

The specific list of "required support and supported features" encompassed by Condition D is provided in Reference 5. Required features are those that are designed with functionally redundant safety-related [divisions]. If a plant has a required feature that has no functionally redundant counterpart, that feature may not be required to be included. This is unlikely, however, since single-

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BASES (continued)

ACTIONS (continued)

failure considerations usually require functional redundancy of safety features. Since the Completion Time allowance for this Required Action is limited to 72 hours, those systems with allowed Completion Times ≥ 72 hours for complete loss of function are not included as required features to be checked.

{VS-BW,CE,W:
Auxiliary feedwater is provided by a [50%]-capacity motor-driven feedwater pump in [Division 1], a [50%]-capacity motor-driven feedwater pump in [Division 2], and a [100%]-capacity turbine-driven feedwater pump. Therefore, assuming that all offsite power is not available (as per the GDC), Condition D reduces the 72-hour Completion Time to DX hours for the case in which auxiliary feedwater function has been reduced to only [50%] of capacity or less.}

{VS-BW,CE,W:
The turbine-driven auxiliary feedwater pump is not included with the "one or more required support or supported features, or both, inoperable that are associated with the other [division] that has an OPERABLE DG" because the feedwater pump is steam driven (as opposed to motor driven), and thus is not "associated" with either [division] of the AC electrical power sources.}

{VS-BW,CE,W:
The Note for Required Action D.2.2 states, "Required Action D.2.2 is only required in MODES 1, 2, and 3, and in MODE 4 when auxiliary feedwater is being used for plant shutdown and startup." This Note is consistent with the Applicability requirements of Specification 3.7.4, "Auxiliary Feedwater System." When the pressure is < [715 psig] the turbine-driven auxiliary feedwater pump need not be capable of meeting the SR limits of SR 3.7.4.2 on developed head to satisfy the OPERABILITY requirements of Required Action D.2.2. The pump must be capable of coming up to speed and delivering flow, however. Furthermore, the licensee shall verify that the pump passed its last SR 3.7.4.2.}

Operation may continue in Condition D for a period that should not exceed DX hours. In this Condition, the remaining OPERABLE DG[s] and offsite circuits are adequate

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BASES (continued)

ACTIONS (continued)

to supply electrical power to the onsite Class 1E Distribution System. The DX-hour limit takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Thus, on a component basis, we may have lost single-failure protection for the required feature's function; however, we have not lost function. Similarly, we take 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. If the Required Actions of Condition D and the associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

E.1 and E.2

Condition E is one required offsite circuit inoperable AND one required DG inoperable. The Required Action is to either restore all required offsite circuits to OPERABLE status within a Completion Time of 12 hours OR restore all required DGs to OPERABLE status within a Completion Time of 12 hours. Condition E has been modified by a Note to indicate that when Condition E is entered with no AC source to one [division], LCO 3.8.7 must be immediately entered. Pursuant to the definition of OPERABILITY, this action should have already taken place; however, it is noted here to indicate that the Completion Time for Condition E under this situation is governed by the Completion Time of Required Action A.1 of LCO 3.8.7.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition E for a period that should not exceed 12 hours. The alternative Completion Time is for the situation in which Condition E was entered with no AC power to one [division], and the Completion Time to restore all required offsite circuits or DGs is then governed by LCO 3.8.7.

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 F (loss of both required offsite circuits). This difference in reliability is offset by the

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BASES (continued)

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susceptibility of this power system configuration to a single bus or switching failure. The 12-hour or the alternate Completion Time limit 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. If Required Action E.1 and Required Action E.2 and their associated Completion Times are not met, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

F.1

Condition F is two required offsite circuits inoperable. Required Action F.1 is to restore at least
{VS-BW,CE,W,BWR/4: [one]}
{VS-BWR/6: two} required offsite
{VS-BW,CE,W,BWR/4: circuit[s]}
{VS-BWR/6: circuits} to OPERABLE status.
The intent of this Required Action is to restore either all required offsite circuits, or all but one required offsite circuit, to OPERABLE status within a Completion Time of 24 hours.

Per Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. 4), operation may continue in Condition F for a period that should not exceed 24 hours. This degradation level 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 source have not been degraded. This degradation level 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

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BASES (continued)

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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 design basis transient or accident. 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 limit provides a period of time to effect restoration of all or all but one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

Per Reference 4, with the available offsite AC source 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 may continue for a total time that should not exceed 72 hours (consistent with the loss of one AC source).

If no offsite source is restored within the first 24-hour period of continued operation, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

G.1

Condition G is two required DGs inoperable. Required Action G.1 is to restore at least {VS-BW,CE,W,BWR/4: [one]} {VS-BWR/6: two} required diesel {VS-BW,CE,W,BWR/4: generator[s]} {VS-BWR/6: generators} to OPERABLE status.

The intent of this Required Action is to restore either all required DGs, or all but one required DG, to OPERABLE status within a Completion Time of 2 hours.

With two DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite

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BASES (continued)

ACTIONS (continued)

electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

Per Reference 4, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. If both DGs are restored within 2 hours, unrestricted operation may continue. If only one DG is restored within these 2 hours, operation may continue for a total time that should not exceed 72 hours (consistent with the loss of one AC source). If no DG is restored within the first 2 hours of continued operation, a controlled shutdown must be performed per Required Action J.1 and Required Action J.2.

H.1

Condition H is three required AC sources inoperable. The Required Action is to enter LCO 3.0.3 immediately.

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 Surveil will cause a loss of function. Therefore, no additional time is justified for continued operation. The plant should be brought promptly to a controlled shutdown as required by LCO 3.0.3. During the shutdown process, the AC electrical power system should be critically monitored, and necessary actions taken, such as cross-connecting a supply to a load, if required, to ensure a safe shutdown.

I.1

Condition I is one required [automatic load sequencer] inoperable. The Required Action is to restore all required [automatic load sequencers] to OPERABLE status within the Completion Time of [2] hours [for Divisions 1 and 2].

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BASES (continued)

ACTIONS (continued)

{VS-BWR/6: If the sequencer is associated with [Division 3], then the Completion Time is [2 hours].}

{VS-BWR/6: [The [2-hour] Completion Time for an inoperable [Division 3] [automatic sequencer] is plant specific. Items to be considered in specifying this Completion Time for a given facility include:

a. The safety function of [Division 3]. If [Division 3] supports only the HPCS function, then there may not even be a [Division 3] [automatic sequencer] because there is only one large load to be connected to the [Division 3] ESF bus. If other ESF functions are supported by [Division 3], then the Completion Time for an inoperable [Division 3] [automatic sequencer] shall be [2 hours]; and

b. The safety function of the [Division 3] [automatic sequencer]:

   1. What is its role in mitigating a DBA?

   2. Does the [Division 3] [automatic sequencer] function as a support system to the [Division 3] DG, [Division 3] offsite circuit, or both? What ESF functions does it support?

   3. What is the role of the [Division 3] [automatic sequencer] in mitigating an SBO?}

Condition I corresponds to the sequencer(s) for [one ESF bus] being inoperable. If the sequencer(s) to [more than one ESF bus] are inoperable, enter LCO 3.0.3.

The sequencer(s) is (are) an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus.] Therefore, loss of an [ESF bus's sequencer] affects every major ESF system in the [division]. The [2]-hour Completion Time for [Divisions 1 and 2] {VS-BWR/6: and [2-hour] Completion Time for [Division 3]} provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that

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BASES (continued)

ACTIONS (continued)

the probability of an accident (requiring sequencer OPERABILITY) occurring during periods where the sequencer is inoperable is minimal.

[For plants that can show that the sequencer's role is less vital, a longer Completion Time may be appropriate. For example, if the ESF loads are block-loaded onto the offsite circuit so that no sequencer operation is required, then it may be possible to show that the sequencer is solely linked to DG OPERABILITY. In such a case, a Completion Time of [72 hours] may be appropriate.]

When a sequencer is inoperable, the associated [ESF bus] is declared inoperable, and LCO 3.8.7 is immediately entered. In LCO 3.8.7 it is determined whether the loss of functional capability exists by verifying whether one or more support or supported features, or both, are inoperable that are associated with the other ESF buses.

J.1 and J.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable AC electrical power sources and sequencers cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The AC source are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with GDC 18 (Ref. 6). 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, "Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Power Plants" (Ref. 2); Regulatory Guide 1.108, "Periodic Testing of DG Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (Ref. 7); and Regulatory Guide 1.137, "Fuel Oil Systems for Standby DGs" (Ref. 8), as addressed in the FSAR.

SR 3.8.1.1

This SR is required only when in Condition A, "One offsite circuit inoperable." Upon the inoperability of an offsite circuit, any remaining required offsite circuits that are OPERABLE must be checked for OPERABILITY within 1 hour of entering Condition A and once per 8 hours thereafter. If additional offsite circuits are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The requirement to perform SR 3.8.1.1 continues until LCO 3.8.1 is met, or until the plant is put in a MODE of operation outside of the Applicability of LCO 3.8.1.

This SR assures proper circuit continuity for the offsite AC power supply to the onsite distribution network and availability of offsite AC power. The breaker alignment verifies that each breaker is in its correct position to ensure distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained.

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of 1 hour and once per 8 hours thereafter takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of offsite power upon the inoperability of one of the other offsite sources. Also, these Frequencies take into account the capacity, capability, redundancy, and diversity of the AC sources; other indications available in the control room, including alarms, to alert the operator to AC sources malfunctions; and the low probability of a DBA occurring during this period.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

It is recognized that an operator could choose not to perform SR 3.8.1.1 within 1 hour and once per 8 hours thereafter. Instead the operator could simply declare the second offsite circuit inoperable and accept a shorter Completion Time. While such action would be within the strict legal interpretation of the TS, it would not normally be prudent. In general, the operator should welcome the latest information on the condition of the plant. Furthermore, by failing to perform the SR on the second circuit, information on common cause failure may go undiscovered.

SR 3.8.1.2

This SR is required only when in Condition C, one DG inoperable. Upon the inoperability of a DG, any required offsite circuits that are OPERABLE must be checked for OPERABILITY within 1 hour of entering Condition C and once per 8 hours thereafter. If offsite circuit(s) are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The requirement to perform SR 3.8.1.2 continues until LCO 3.8.1 is met, or until the plant is put in a MODE of operation outside of the Applicability of LCO 3.8.1.

This SR assures 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 distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained.

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of 1 hour and once per 8 eight hours thereafter takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of offsite electrical power upon the inoperability of one of the other offsite sources. Also these Frequencies take into account

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the capacity, capability, redundancy and diversity of the AC sources; other indications available in the control room, including alarms, to alert the operators to AC sources malfunctions; and the low probability of a DBA occurring during this period.

It is recognized that an operator could choose not to perform SR 3.8.1.2 within 1 hour and once per 8 hours thereafter. Instead the operator could simply declare the offsite circuit inoperable and accept a shorter Completion Time. While such action would be within the strict legal interpretation of the TS, it would not normally be prudent. In general, the operator should welcome the latest information on the condition of the plant. Furthermore, by failing to perform the SR on the offsite circuit(s), information on common cause failure may go undiscovered.

SR 3.8.1.3

This SR is only required when in Condition C, one DG inoperable. Each and every required DG inoperability must be evaluated for common cause failure potential by performance of SR 3.8.1.3, regardless of when the DG is returned to OPERABLE status. If additional DGs are found inoperable, they must be declared inoperable, and the corresponding Conditions of LCO 3.8.1 must be entered.

The purpose of this SR is to determine absence of common cause for the DG inoperability for any remaining required DGs that are OPERABLE. This can be done either by analysis and reasoning (item A.1 of SR 3.8.1.3) or by starting the DG(s) that are OPERABLE (item B.1 of SR 3.8.1.3).

This Surveillance Frequency is justified based on the necessity to maintain a reliable AC electrical power system. The Frequency of once within [8] hours of entering Condition C takes into account the time required to perform the Surveillance and the difficulty in completion. This is balanced against the desirability of having accurate and reliable information about remaining sources of onsite electrical power upon the inoperability of one of the other onsite sources. Also these Frequencies take into account the capacity, capability, redundancy, and diversity of the AC sources; other indications available in the control room,

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

to alert the operators to AC sources malfunctions; and the low probability of a DBA occurring during this period.

SR 3.8.1.4

This SR assures 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 distribution buses and loads are connected to their preferred power source. The check on devices that provide the separation and independence assures that protective relaying and interrupting devices are OPERABLE so that circuit independence can be maintained. The 7-day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and its status is displayed in the control room.

SR 3.8.1.5 and SR 3.8.1.17

These SRs help to ensure the availability of the standby electrical power supply to mitigate design basis transients and accidents and maintain the plant 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 a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelubricating period in accordance with vendor recommendations. For the purposes of this testing, the DGs shall be started from standby conditions.

Standby conditions for a [Division 1 or 2] DG means the diesel engine coolant and oil are being continuously circulated and temperature maintained consistent with manufacturer recommendations.
{VS-BWR/6: Standby conditions for [Division 3] DG means the lubricating oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by natural circulation.}

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

All engine starts for SR 3.8.1.5 may be preceded by warmup procedures as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine are minimized. This is the intent of Note 3 of SR 3.8.1.5.

SR 3.8.1.5 has been modified by a fourth Note, Note 4, requiring the performance of SR 3.8.1.6 immediately after SR 3.8.1.5. The exceptions (a) and (b) are for cases in which less than a full complement of AC sources, may be available. Therefore, the performance of SR 3.8.1.6 is not required because it requires the paralleling of two of the remaining AC sources, which may compromise the AC source independence.

SR 3.8.1.17 requires that, on a 184-day Frequency, the DG start from standby conditions and achieve required voltage and frequency within 10 seconds. The 10-second requirement supports the assumptions in the design basis LOCA analysis (Ref. 9). The 10-second start requirement may not be applicable to SR 3.8.1.5 (see Note 3 of SR 3.8.1.5), which is usually performed on a 31-day Frequency. Since SR 3.8.1.17 does require a 10-second start, it is more restrictive than SR 3.8.1.5, and it may be performed in lieu of SR 3.8.1.5. This is the intent of Note 1 of SR 3.8.1.5. The normal 31-day Frequency for SR 3.8.1.5 (see DG test schedule, Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 2). The 184-day Frequency for SR 3.8.1.17 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 10). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.17 has been modified by a second Note, Note 2, which requires, following the completion of SR 3.8.1.17, the performance of SR 3.8.1.6. An exception is when SR 3.8.1.17 is required by SR 3.8.2.1. In this situation, less than a full complement of AC sources may be available. Therefore, the performance of SR 3.8.1.6 is not required because it requires the paralleling of two of the remaining AC sources, which may compromise the AC source independence.

SR 3.8.1.6

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

equivalent of the maximum expected accident loads. A third Note to this SR, Note 3, indicates that this Surveillance should only be conducted on one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. A minimum run time of 60 minutes is required to stabilize engine temperatures. Actual run time should be in accordance with vendor recommendations with regard to good operating practice and should be sufficient to ensure that cooling and lubrication are adequate for extended periods of operation, while minimizing the time that the DG is connected to the offsite source.

In order to assure 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 in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design inductive loading.

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 (Ref. 10).

Note 2 modifies this Surveillance by stating that momentary transients because of 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 teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The normal 31-day Frequency for this Surveillance (see DG test schedule, Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 2).

SR 3.8.1.7

This Surveillance verifies that, without the aid of the refill compressor, sufficient air-start capacity for each DG

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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. If the pressure is less than the value specified in this SR, the DG shall be declared inoperable. The five-start-cycles requirement is intended to provide redundancy for the DG start capability in the event that the hot DG does not start on the first attempt.

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 3.8.1.8

This SR provides verification that each DG day [and engine-mounted fuel] tank contains enough fuel oil, measured from the low-level alarm setpoint, to operate the DG for at least 1 hour at full load. If the day [and engine-mounted fuel] tank level is less than the required limit, the DG is inoperable.

The 31-day Frequency is adequate to ensure 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.

SR 3.8.1.9

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 facility in a safe shutdown condition and to bring in replenishment fuel from an offsite location. If the storage tank level is less than the required limit, the DG is inoperable.

The 31-day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low-level alarms are

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.10

This Surveillance ensures that sufficient lubricating oil inventory is available to support at least 7 days of full-load operation for each DG. The [500]-gal requirement is based on the DG manufacturer's consumption values for the run time of the diesel. Implicit in this SR is the requirement to verify the capability to transfer the lubricating-oil from its storage location to the DG. If it can be demonstrated that the DG lubricating-oil sump can hold adequate inventory for 7 days of full-load operation without the level reaching a dangerous point, then the quantity or level of lubricating oil in the sump can be used in this SR. If the lubricating oil inventory is less than the limit, the DG is inoperable.

A 31-day Frequency is adequate to ensure that a sufficient lubricating-oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

SR 3.8.1.11

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/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. The tests, limits, and applicable American Society for Testing Materials (ASTM) standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4054-[ ];

b. Verify in accordance with the tests specified in ASTM D975-[ ] that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83° but ≤ 0.89° or an API gravity at 60°F of ≥ 27° but ≤ 39°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes but ≤ 4.1 centistokes, and a flash point ≥ 125°F; and

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[ ].

These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case shall the time between receipt of new fuel and conducting the tests exceed 31 days.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not constitute a DG OPERABILITY concern since the fuel oil is not added to the storage tanks.

SR 3.8.1.12

Within 31 days following the initial new fuel-oil sample, this Surveillance is performed to establish that the other properties specified in Table 1 of ASTM D975-[ ] are met for new fuel oil when tested in accordance with ASTM D975-[ ], except that the analysis for sulfur may be performed in accordance with ASTM D1522-[ ] or ASTM D2622-[ ]. The 31-day period is acceptable because the fuel-oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. For the same reason, should one or more of these properties not be within limits, there is no need to declare the DG inoperable. It is acceptable to continue operation for up to [31] days while measures are taken to ensure that the properties of the mixed fuel oil are within limits or that the fuel-oil properties are being restored to within limits. If after continued operation for [31] days the properties of the mixed fuel oil are still not within limits, the DG shall be declared inoperable.

SR 3.8.1.13

This Surveillance is an integral part of a comprehensive program to ensure the availability of high-quality fuel oil for the DGs at all times. By testing for particulate on a 31-day basis, information regarding the condition of stored fuel oil can be obtained and trended.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Fuel-oil degradation during long-term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel-oil injection equipment, however, which can cause engine failure. If particulate is removed from stored fuel oil by circulating the oil through filters (other than diesel engine filters), the fuel oil can be restored to acceptable condition and its storage life extended indefinitely. By obtaining and trending particulate data, it is possible to determine when stored-fuel-oil cleanup will be necessary. This is done before the maximum allowable particulate concentration is reached.

Particulate concentrations should be determined in accordance with ASTM D2276-[ ], Method A. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent lab testing in lieu of field testing. In the case(s) where the total stored-fuel-oil volume is contained in two or more interconnected tanks, each tank must be considered and tested separately.

The Frequency of this Surveillance takes into consideration fuel-oil degradation trends that indicate that particulate concentration is unlikely to change between Frequency intervals.

There is no quantitative data regarding the capability of diesel engines to operate for prolonged periods of time with fuel-oil particulate concentrations in excess of 10 mg/l. Therefore, if this limit is reached, the associated DG shall be declared inoperable. In practice, however, this should not present a problem since the concept behind this SR is to establish fuel-oil degradation trends, which will provide an alert to the need for corrective action prior to impacting on DG OPERABILITY.

SR 3.8.1.14 and SR 3.8.1.15

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

fuel-oil day [and engine-mounted] tanks and from storage tanks once every 31 days will eliminate the necessary environment for survival. This is the most effective means of controlling microbiological fouling. In addition, it will eliminate 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 will minimize fouling as well as provide data regarding the watertight integrity of the fuel-oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 8).

SR 3.8.1.16

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. This is required to support the 7-day 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. 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 Section XI code; however, the design of fuel-transfer systems is such that pumps will operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day [and engine-mounted] tanks during or following DG 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. Upon failure of this SR, the DG shall be declared inoperable immediately.

SR 3.8.1.17

See SR 3.8.1.5.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Transfer of each [4.16 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 [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 has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 2 has been included in this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.19

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 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. [For this facility, the largest single load for each DG and its horsepower rating is as follows:] As required by IEEE-308, 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. [For this facility, the SR 3.8.1.19

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

frequency ([63] Hz) for each DG and one of the two above criteria used to arrive at this number are as follows:]

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 2) recommendations for response during load sequence intervals. The [3] seconds specified is equal to 60% of a typical 5-second interval. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.19a corresponds to the maximum frequency excursion, while SR 3.8.1.19b and SR 3.8.1.19c are steady-state voltage and frequency values that the system must recover to following load rejection. The [18-month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 7).

In order to assure 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 in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading. If the facility uses the actual single largest load to perform this test, then the power factor will be set by that load.

This SR has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

may occur because of a system fault or inadvertent breaker tripping. This Surveillance verifies proper engine-generator load response under the simulated test conditions. This test will simulate the loss of the total connected load that the DG will experience following a full-load rejection and verify that the DG will not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continue to be available, this response will assure 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 assure 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 in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

This SR has been modified by a Note, Note 1, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbation to the electrical distribution systems that could result in a challenge to continued steady-state operation.

The [18-month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 7) and is intended to be consistent with expected fuel-cycle lengths.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.21

As required by Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(1), this Surveillance demonstrates the as-designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

from the loss of offsite power, including shedding of the non-essential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG automatic start time of [10] seconds is derived from requirements of the accident analysis to respond to a design basis large-break LOCA. The minimum steady-state output voltage of [3744] V is [90%] of the nominal [4160 V] output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% of 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of nameplate rating.

The specified maximum steady-state output voltage of 4576 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors will be no more than the maximum rated operating voltages.

The specified minimum and maximum steady-state output frequency of the DG is [58.8] Hz and [61.2] Hz respectively. This is equal to ± 2% of the 60 Hz nominal frequency and is derived form the recommendations given in Regulatory Guide 1.9 (Ref. 2) that 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 Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(1), 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 a Note, Note 1, stating that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by natural circulation}.

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.22

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time ([10] 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 3.8.1.22d and SR 3.8.1.22e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on a ESF signal without loss of offsite power. The bases for the time, voltage, and frequency tolerances specified in this Surveillance are discussed under SR 3.8.1.21, above.

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. {VS-BWR-6: For the [Division 3] DG, standby conditions means the lubricating oil is heated and continuously circulated

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by means of natural circulation}.

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

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

SR 3.8.1.23

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 ESF actuation test signal and critical protective functions (engine overspeed, generator differential current, and low lubricating oil pressure) 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 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

performed on the [18-month] Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR has been modified by a Note, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required DG from service.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.24

Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(3), 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 the continuous rating of the DG and 2 hours of which is at a load equivalent to the 2-hour rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.5, and for gradual loading, discussed in SR 3.8.1.6, are applicable to this SR.

In order to assure that the DG is tested under load conditions that are as close to design conditions as possible, testing shall be performed using a power factor in the range: [0.8] ≤ power factor ≤ [0.9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience. Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(3), takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with expected fuel-cycle lengths.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance has been modified by a Note, Note 1, which 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 teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in MODE 1 or 2. The reason for this is that during operation with the reactor critical, performance of this SR could potentially cause perturbations to the electrical distribution systems that could result in a challenge to continued steady-state operation and, as a result, to plant safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.25

This Surveillance demonstrates that the diesel engine can restart from a hot condition and achieve the required voltage and frequency within [10] seconds. The [10]-second time is derived from the requirements of the accident analysis to respond to a design basis large-break LOCA. The requirement that the diesel have operated for at least 2 hours at full-load conditions prior to performance of this Surveillance is based on manufacturer's recommendations for achieving hot conditions. The bases for the voltage and frequency tolerances are discussed in the Bases for SR 3.8.1.21.

The Surveillance demonstrates the DG capability to respond to accident signal while hot, such as subsequent to shutdown from normal Surve llances. The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(5).

In order to assure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed sing a power factor in the range: [0.8] ≤ power factor ≤ [9]. This power factor range shall be chosen to be representative of the actual design basis inductive loading that the DG would experience.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Alternatively, it may be conservatively chosen as a range that contains power factors that are numerically smaller than the power factors that are representative of the actual design basis inductive loading.

This SR has been modified by a Note, Note 1, which states that the SR shall be performed within 5 minutes of shutting down the DG after it has operated more than 2 hours at between [5450 and 5740] kW. This is to ensure that the test is performed with the diesel sufficiently hot.

This SR has been modified by a second Note, Note 2, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturers. The reason for this is to minimize wear and tear on the diesel during testing.

This Surveillance has been modified by a third Note, Note 3, which states that momentary transients due to changing bus loads do no invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

SR 3.6.1.26

As required by Regulatory Guide 1.108 (Ref.7), paragraph 2.a.(6), this Surveillance assures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and 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 rated speed and voltage, the output breaker is open and can receive and auto-close signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.1.(6), and takes into consideration plant conditions required to perform the Surveillance.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

This SR has been modified by a Note, Note 1, which states that the SR must not performed in {VS-BW,CE,W: MODE 1, 2, 3, OR 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.27

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if a LOCA actuation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 11), paragraph 6.2.6(2).

The [18-month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(8), 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 a Note, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2 or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.28

As required by Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(2), 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

accident conditions, prior to connecting the diesel generators to their appropriate 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 rated voltage and frequency, the DGs are then connected to their respective bus. Loads are then sequentially connected to the bus by the [automatic load sequencer]. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor-starting currents. 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. Reference 3 provides a summary of the automatic loading of ESF buses.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 7), paragraph 2.a.(2), 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 a Note, Note 1, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 2 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.29

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time ([10] seconds) from the design basis actuation signal (LOCA signal). SR 3.8.1.29b and SR 3.8.1.29c ensure that permanently connected loads remain energized from the offsite electrical power system, and that emergency loads are energized [or auto-connected through the load sequencer] to the offsite electrical power system. Before the last [sequencer] load step, a loss of offsite power is simulated. It must then be shown that the AC

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

sources and sequencer reset themselves so that the powering of the loads can begin all over again, this time with the DG as the power source.

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating circulation.}

This SR has been modified by a second Note, Note 2, which states that the SR must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

The Frequency of [36 months] alternated with SR 3.8.1.30 means that once within [18 months] either SR 3.8.1.29 or SR 3.8.1.30 is completed for each DG. Then once within the following [18 months] the other SR, SR 3.8.1.30 or SR 3.8.1.29, is completed for each DG. This Frequency 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]. [For this facility, operating experience has demonstrated that the Frequency for this SR is adequate for the following reasons:]

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.30

In the event of 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 under SR 3.8.1.22 above, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal.

The Frequency of [36 months] alternated with SR 3.8.1.29 means that once within [18 months] either SR 3.8.1.29 or SR 3.8.1.30 is completed for each DG. Then once within the following [18 months] the other SR, SR 3.8.1.30 or SR 3.8.1.29, is completed for each DG. This Frequency 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]. For this facility, operating experience has demonstrated that the Frequency for this SR is adequate for the following reasons:]

This SR has been modified by a Note, Note 1, which states that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. {VS-BWR/6: For the [Division 3] DG, standby conditions means the lubricating oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by means of natural circulation}.

This SR has been modified by a second Note, Note 2, which states that the SE must not be performed in {VS-BW,CE,W: MODE 1, 2, 3, or 4} {VS-GE: MODE 1, 2, or 3}. The reason for this is that performing the SR would remove a required

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Note 3 has been added to this SR to acknowledge that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.31

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. 8), paragraph 2.f. This Sr also requires the performance of the Section XI examinations of the tanks. To preclude the introduction of surfactants in the fuel system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents.

SR 3.8.1.32

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 1.108 (Ref. 7), paragraph 2.b and Regulatory Guide 1.137 (Ref. 8), paragraph C.2.f.

This SR has been modified by a Note that all DG starts may be preceded by prelubricating procedures as recommended by the manufacturer. The reason for this is to minimize wear on the DG during testing. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. {VS-BWR/6: Standby conditions for [Division 3] DG means the lubricating oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by means of natural circulation.}

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

DG Test Schedule

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 2). The purpose of this test schedule is to provide sufficiently timely that is test data to establish a confidence level associated with the goal to maintain DG reliability above 0.95 per demand.

Per Regulatory Guide 1.9, Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced four or more valid failures in the last 25 demands, the maximum time between tests is reduced to 7 days. Four failures in 25 demands 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, four failures in the last 25 demands may only be a statistically probable distribution of random events. Increasing the test Frequency will allow for 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, General Design Criterion 17, "Electric Power Systems."

2. Regulatory Guide 1.9, Rev. [ ], "Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," [date].

3. [Plant Name] FSAR, Tables [8.3-1 to 8.3-3], "[Title]."

4. Regulatory Guide 1.93, Rev. [ ], "Availability of Electric Power Sources," [date].

5. [List of equipment (required features) referred to in Conditions B and D].

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BASES (continued)

REFERENCES (continued)

6. Title 10, Code of Federal Regulations, Part 50, General Design Criterion 18, "inspection and Testing of Electric Power Systems."

7. Regulatory Guide 1.108, Rev. [ ], "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," [ ].

8. Regulatory Guide 1.137, Rev. [ ] "Fuel Oil Systems for Standby Diesel Generators," [date].

9. [[Plant Name] FSAR, Section [ ]], [This reference is to provide the assumptions of the design basis LOCA].

10. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

11. IEEE Standard 308-[ ], "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources—Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for Specification 3.8.1, "AC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC power sources and associated distribution systems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel-handling accident.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to AC sources, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC sources comprise a typical support system.

In general, when the plant is shut down the TS requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show that a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops - MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation - Low Water Level."}} {VS-GE: The OPERABILITY of the two Residual Heat Removal shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual Heat Removal—Low Water Level."} Therefore, in these conditions, [Division 1 and 2] AC sources are required to be OPERABLE as support systems.

Furthermore, by application of GDC 34, "Residual Heat Removal," and the design basis definition of <u>operability</u> (See AC Sources and Component OPERABILITY, Bases for

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Specification 3.8.1), it is clear that each RHR pump must be backed up by separate and independent onsite and offsite sources.

Thus, to meet the design basis definition of operability and GDC 34, four AC sources are required when two RHR pumps are required OPERABLE. As discussed above, however, each plant may have put in additional measures to help mitigate the potential consequences of an accident in these operating MODES. For those plants, Specification 3.8.2 is written such that three out of four AC sources will suffice.

The AC sources satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

LCO 3.8.2.a and LCO 3.8.2.b require that one offsite circuit and one diesel generator be OPERABLE (see Bases 3.8.1) and capable of supplying the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC and DC sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC and DC sources and the distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.2.c requires that they be powered by a third separate and independent, readily available AC source. Readily available means that the source can be made OPERABLE and put into operation, if necessary, within a time commensurate with the safety importance of the redundant loads.

{VS-BWR/6: LCO 3.8.2.d requires an offsite circuit to power the high pressure core spray (HPCS) system when it is required to be OPERABLE, or when other loads assigned to the HPCS system [division] are required to be OPERABLE, or both. The requirements set forth in this LCO may need to be restructured depending on the functions required to be accomplished during these modes of operation by the required loads assigned to [Division 3]. [For this facility, the

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BASES (continued)

LCO (continued)

functions associated with the required loads assigned to [Division 3] during these modes of operation are as follows:]

See the Bases of Specification 3.8.1 for additional information on AC source OPERABILITY and AC source support and supported systems.

LCO 3.8.2 specifies the minimum AC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE:[or moving loads over irradiated fuel in the primary or secondary containment]}. It 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 draindown).

As described in the previous section, "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. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The AC sources comprise a typical support system.

APPLICABILITY

The AC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]} provide assurance that:

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BASES (continued)

APPLICABILITY (continued)

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown 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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

AC power requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.1, "AC Sources—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required AC electrical power sources inoperable, some equipment is not receiving the minimum support it needs. It is, therefore, required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit's safety systems.

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

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BASES (continued)

ACTIONS (continued)

should be completed as quickly as possible in order to minimize the time the unit's safety systems may be without power.

Required Action A.6 verifies that the Required Actions have been initiated for those supported systems declared inoperable as a result of the total loss of power to a power distribution subsystem within the same Completion Time as that specified for Required Action A.5.

This Required Action has been modified by a Note to clarify that Required Action A.6 needs to be executed only when there are no AC power sources to one or more [divisions] of the onsite Class 1E Power Distribution System.

Required Action A.6 ensures that those identified Required Actions associated with supported systems affected by the total loss of power to a [division] of AC and DC power distribution subsystem have been initiated by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified support systems' Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 lists 16 SRs from LCO 3.8.1 that are required to be met. Therefore, see the corresponding Bases for Specification 3.8.1 for a discussion of each SR.

REFERENCES

1. [Unit name] FSAR, Section [ ], "[Title]."
2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 DC Sources—Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency 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).

{VS-BW,CE,W,BWR/4: The [250/125] Vdc electrical power system consists of two independent and redundant safety-related Class 1E DC electrical power subsystems ([Division 1 and 2]).} {VS-BWR/6: The [250/125] Vdc electrical power system consists of three independent Class 1E DC electrical power subsystems ([Divisions 1, 2, and 3]).} Each subsystem consists of [two] battery banks [(each bank [50%] capacity)], associated battery charger(s), ([one] per bank), and all the associated control equipment and interconnecting cabling. [Additionally there is [one] spare battery charger per subsystem, which provides backup service in the event that the preferred battery charger is out of service. If the spare battery charger is substituted for one of the preferred battery chargers, then the requirements of independence and redundancy between subsystems are maintained.]

During normal operation, the [250/125] Vdc load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

Each of the [Division 1 and 2] electrical power subsystems provides the control power for its associated Class 1E AC-power-load group, [4.16] kV switchgear, and [480] V load centers. Also, these DC subsystems provide DC electrical power to the inverters, which in turn power the AC vital buses. {VS-BWR/6: The [Division 3] DC electrical power

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BASES (continued)

BACKGROUND (continued)

subsystem provides DC motive and control power as required for the High Pressure Core Spray System diesel generator (DG) set control and protection, and all [Division 3]-related control.]}

The DC-power distribution system is described in more detail in Bases for Specifications 3.8.7, "Distribution System—Operating," and 3.8.8, "Distribution System—Shutdown."

In the event of loss of all unit AC power, which is beyond the design bases, the DC system is the only electrical power source available to monitor critical plant parameters and operate selected equipment.

Each battery bank of the [Division 1 and 2] DC electrical power subsystem consists of [120] lead-[calcium] cells with a continuous discharge rating of [1650] Ah for [8] hours to [210] Vs at [77]°F. Plant battery operating voltage is [250/125] Vs, and each battery has adequate storage capacity to carry the required load continuously for at least [2] hours and to perform [three] complete cycles of intermittent loads (Ref. 4). Capacity is adequate for loss-of-coolant accident (LOCA) conditions or any other emergency shutdown.

{VS-BWR/6: The [Division 3] DC electrical power subsystem consists of a [125] V, [60]-cell lead-calcium battery with a continuous discharge of [1000] Ah for [8] hours to [105] V at [77]°F; the battery has adequate storage to carry the required load continuously for at least [2] hours and to perform [three] complete cycles of intermittent loads (Ref. 4). Capacity is adequate for LOCA conditions or any other emergency shutdown.}

The battery chargers of [Division 1 and 2] DC electrical power subsystems are rated at [300] amps with 0.5% voltage regulation with an AC-supplied variation of [480 V ± 15%] in voltage and [60 Hz ± 5%] in frequency (Ref. 4).

{VS-BWR/6: The battery charger for [Division 3] DC electrical power subsystem is rated at [150] amps with 0.5% voltage regulation with an AC-supplied variation of [480 V ± 15%] in voltage and [60 Hz ± 5%] in frequency (Ref. 4).}

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BASES (continued)

BACKGROUND (continued)

Each [250/125] Vdc battery subsystem 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 subsystems such as batteries, battery chargers, or distribution panels.

Battery rooms are continuously ventilated in order to prevent accumulation of hydrogen and to maintain design temperature. The ventilation system limits the hydrogen accumulation to less than [1]% of the total of battery room volume (Ref. 4). The threshold of ignition is 4% and maximum hydrogen generation occurs during overcharging.

The batteries for [Division 1 and 2] DC electrical power subsystem are sized to produce required capacity at [80]% of nameplate rating, corresponding to warranted capacity at end-of-life cycles and the 100% design demand. Battery size is based on [125]% of required capacity and, after selection of an available commercial battery, results in a battery capacity in excess of [150]% of required capacity. The voltage limit is [2.13] V per cell, which corresponds to a total minimum voltage output of [128] V per battery bank (Ref. 4). The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 5).

{VS-BWR/6: The battery for [Division 3] DC electrical power subsystem are sized to produce required capacity at [80]% of nameplate rating, corresponding to warranted capacity at end-of-life cycles and the 100% design demand. Battery size is based on [125]% of required capacity and, after selection of an available commercial battery, results in a battery capacity in excess of [150]% of required capacity. The voltage limit is [2.13] V per cell, which corresponds to a total minimum voltage output of [128] V per battery bank (Ref. 4).}

Each battery charger of [Division 1 and 2] DC electrical power subsystem has ample power-output capacity for the steady-state operation of 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 the battery bank from the

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BASES (continued)

BACKGROUND (continued)	design minimum charge to its fully charged state within 24 hours while supplying normal steady-state loads (Ref. 4). {VS-BWR/6: The battery charger of [Division 3] DC electrical power subsystem has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state in [8] hours while supplying normal steady-state loads (Ref. 4)].}
APPLICABLE SAFETY ANALYSES	The initial conditions of design basis transient and accident analyses in the FSAR, [Chapter 6, "Engineered Safety Features"], and [Chapter 15, "Accident Analyses"], assume that ENGINEERED SAFETY FEATURE (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite power or offsite AC sources, DC sources, and associated distribution systems 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. DC Sources—Operating satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	As described in the Background section, each [divisional] DC electrical power subsystem consists of [two] battery bank(s), associated battery charger(s) and the corresponding control equipment and interconnecting cabling within the [division].

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BASES (continued)

LCO (continued)

All 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 Design Basis Accident (DBA). Loss of any [divisional] DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

A DC electrical power subsystem is OPERABLE provided:

a. All of its required battery bank(s) and battery charger(s) are connected to their associated DC bus(es) and are operating; and

b. All of its required battery bank(s) and battery charger(s) are OPERABLE.

Furthermore, for DC subsystems to be OPERABLE, they must be capable of performing their intended functions, have all support systems OPERABLE, and have successfully completed all SRs.

[For this facility, an OPERABLE [divisional] DC electrical power subsystem consists of the following:]

[For this facility, the following support systems are required OPERABLE to ensure [divisional] DC electrical power subsystem OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare DC electrical power subsystems inoperable and their justification are as follows:]

[For this facility, the supported systems affected by the inoperability of a DC electrical power subsystem and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES {VS-BW,CE,W: 1, 2, 3, and 4}{VS-GE: 1, 2, and 3} to ensure safe plant operation and to ensure that:

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BASES (continued)

APPLICABILITY (continued)

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.

DC electrical power requirements for MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} are addressed in the Bases for Specification 3.8.4, "DC Sources—Shutdown."

ACTIONS

A.1 and A.2

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power {VS-BW,CE,W,BWR/4: subsystem has} {VS-BWR/6: subsystems have} the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst-case single failure would, however, result in {VS-BW,CE,W,BWR/4: the complete loss of the [250/125] Vdc electrical power system} {VS-BWR/6: only one DC electrical power subsystem being OPERABLE} with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2-hour Completion Time is based on Regulatory Guide 1.93 (Ref. 6) and reflects a reasonable time to assess plant status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, prepare to effect an orderly and safe plant shutdown. {VS-BWR/6: However, if the inoperable DC electrical power subsystem is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] DC electrical power subsystem supports; furthermore, the number chosen for the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] DC electrical power subsystem inoperability.

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BASES (continued)

ACTIONS (continued)

For example, if the [Division 3] batteries support only the [Division 3] DG, then a Completion Time of [72 hours] would be appropriate, consistent with the Completion Time for an inoperable [Division 3] DG.

If the [Division 3] batteries support both the [Division 3] DG and the [Division 3] offsite circuit, then the Completion Time will be governed by Condition E of Specification 3.8.1.

If the [Division 3] batteries support even more items, such as a [Division 3] sequencer or other [Division 1 and 2] ESF functions, then a [2-hour] Completion Time is appropriate.}

Required Action A.2 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one [division] DC electrical power subsystem have been initiated and within the same Completion Time as that of Required Action A.1.

Required Action A.2 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the [division] DC electrical power subsystem have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified supported system Required Actions are as follows:]

B.1

With two {VS-BWR/6: or more} required [divisions of] DC electrical power subsystems inoperable, the plant is in a condition outside the accident analysis as discussed in A.1, above. Therefore, LCO 3.0.3 must be entered immediately.

C.1

With one [division] DC electrical power subsystem inoperable AND one or more required support or supported features, or both, inoperable associated with the OPERABLE [division] of DC electrical power subsystems, or with opposite OPERABLE AC and DC electrical power distribution subsystems, or both,

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BASES (continued)

ACTIONS (continued)

there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs for the support or supported feature, or for both, take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6} {VS-GE: 12} hours and in MODE {VS-BW,CE,W: 5} {VS-GE: 4} within 36 hours. The Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE {VS-BW,CE,W: 5} {VS-GE: 4} is consistent with the time required in Regulatory Guide 1.93 (Ref. 6).

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR is based on the battery cell parameter values defined in Table 3.8.3-1. 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

Category A defines the normal parameter limit for each designated pilot cell in each battery. The chosen pilot cells are the weakest cells in the battery based on previous test results. These cells are monitored closely as an indication of battery performance.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 7), with the extra 1/4" allowance above the high-water-level indication for

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

operating margin to account for temperatures and charge effects. In addition to this allowance, a footnote to Table 3.8.3-1 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. 7) 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 recommendations of IEEE-450 (Ref. 7), which state that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells. Because resistivity decreases and the charging current increases as the temperature of electrolyte increases, in order to maintain a constant cell voltage, IEEE-450 states that if a warmer cell is below 2.13 V its voltage can be corrected by adding 0.003 V for each degree Fahrenheit (0.005 V/°C) that the cell temperature exceeds the average temperature of other cells. Nevertheless, considering that having dissimilar cell temperatures is an undesirable situation, it is not expected that this correction will have to be made. Instead, appropriate plant preventive actions should be established in order to eliminate the possible causes of the temperature differential.

The Category A limit specified for specific gravity for each pilot cell is ≥ [1.200] (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. 7), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings shall be corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), add 1 point (0.001) to the reading; subtract 1 point for each 3°F below 77°F. The specific gravity of the electrolyte in a cell will increase with a loss of water due to electrolysis or evaporation. A Note in Table 3.8.3-1 requires the above-mentioned correction

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < [2] amps on float charge. This current provides, in general, an indication of overall battery condition.

Because of specific-gravity gradients that are produced during the recharging process, delays of several days [3 to 7] 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 designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 7). A footnote to Table 3.8.3-1 allows the float charge current to be used as an alternate to specific gravity following a battery recharge.

Category B

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out because of a degraded condition or for any other reason.

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 ≥ [1.195] (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells ≥ [1.205] (0.010 below the manufacturer's fully charged, nominal specific gravity). These values 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 will not mask overall degradation of the battery. A Note to Table 3.8.3-1 requires correction of specific gravity for electrolyte temperature and level. This level correction is not required when battery charging current is < [2] amps on float charge.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

Category C

Category C defines the allowable values 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 allowable value, the assurance of sufficient capacity described above no longer exists and the battery must be declared inoperable.

The Category C allowable values 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 allowable value for float voltage is based on IEEE-450 (Ref. 7), 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 allowable value of average specific gravity is based on manufacturer's recommendations ($\geq$ [1.195], 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 will not mask overall degradation of the battery. The Notes to Table 3.8.3-1 that apply to Category A specific gravity are also applicable to Category C specific gravity.

The SR to verify Category A cell parameters is consistent with IEEE-450 (Ref. 7), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells. If pilot cells have one or more battery cell parameters not within Category A limits, the electrolyte level and float voltage of the pilot cells should be verified to meet Category C allowable values within 1 hour. This check will provide a quick indication of the status of the remainder of the battery cells. One hour provides sufficient time to inspect the electrolyte level and to

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 allowable values are met provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery will still be 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 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 allow time to fully restore the battery cell parameters to normal limits, this time is acceptable. When any battery parameter is outside the Category C allowable value 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.

SR 3.8.3.2

Verifying battery terminal voltage while on float charge for the [258/129] V batteries 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 a 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. 7).

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

This SR is based on the battery cell parameters defined in Table 3.8.3-1. The meaning of these different parameters is explained in SR 3.8.3.1 above. The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 7). In addition, within 24 hours of a battery discharge < [110] V or a battery overcharge > [150] V, the battery must be demonstrated to meet Category B limits. This inspection is also consistent with IEEE-450 (Ref. 7), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurred as a consequence of such discharge or overcharge. The steps to follow in case one or more battery cell parameters are not within limits are described above in SR 3.8.3.1.

SR 3.8.3.4

This Surveillance, verification that the average temperature of representative cells is ≥ [60°F], is consistent with a recommendation of IEEE-450 (Ref. 7), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. IEEE-450 suggests taking the temperature of every sixth cell.

While higher-than-normal operating temperatures increase battery capacity, increase internal discharge, lower cell voltages for a given charge current, and raise charging current for a given charge voltage, they decrease battery life.

Lower-than-normal temperatures have the opposite effect, acting to inhibit or reduce battery capacity. Normal battery operating temperatures are [60°]F to [90°F], with a recommended operating temperature of [77]°F. This SR ensures that the operating temperatures remain within an acceptable operating range. These limits are based on manufacturer's recommendations.

SR 3.8.3.5

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each

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SURVEILLANCE REQUIREMENTS (continued)

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 shall 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. In addition, consistent with IEEE-450 (Ref. 7), SR 3.8.3.7 and SR 3.8.3.8 require yearly visual inspection, to detect corrosion, and yearly resistance measurements of connections.

SR 3.8.3.6

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.

This SR is consistent with IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.3.7 and SR 3.8.3.8

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 help 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 connection resistance limits are the same as those stated in SR 3.8.3.5 above.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequencies of 12 months are consistent with IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and inspection of cell-to-cell and terminal connection resistance on a yearly basis.

SR 3.8.3.9

This SR requires that each battery charger be capable of supplying [400] amps and [250/125] V for ≥ [8] hours. These requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 8), 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 ensures that these requirements can be satisfied. This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} since it would require the DC electrical power subsystem to be inoperable during performance of the test.

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.

SR 3.8.3.10

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 should correspond to the design duty cycle requirements as specified in Reference 4. Reference 4 provides load requirements for DC electrical power subsystems. [Optionally, the design duty-cycle requirements may be defined here].

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 8) and Regulatory Guide 1.129 (Ref. 9), which state that the battery-service test should be performed during refueling

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

operations or at some other outage, with intervals between tests not to exceed 18 months.

A Note to SR 3.8.3.10 allows the once-per-60-months performance of SR 3.8.3.11 in lieu of SR 3.8.3.10. This substitution is acceptable because SR 3.8.3.11 represents a more severe test of battery capacity than SR 3.8.3.10.

This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} since it would require a DC electrical power subsystem to be inoperable during performance of the test.

SR 3.8.3.11

A battery performance 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. 7) and IEEE-485 (Ref. 5). 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.

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. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is below the manufacturer's rating. An additional SR calls for a performance test on a newly installed battery within 24 months. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 7).

This Surveillance is required to be performed during {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5}, since

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

it would require the DC electrical power subsystem to be inoperable during performance of the test.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 17, "Electric Power System."

2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," U.S. Nuclear Regulatory Commission, March 10, 1971.

3. IEEE-308 [1978], "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," Institute of Electrical and Electronic Engineers.

4. [Unit Name] FSAR, Section [ ], "[Title]."

5. IEEE-485 [1983], "Recommended Practices for Sizing Large Lead Storage Batteries for Generating Stations and Substations," Institute of Electrical and Electronic Engineers, June 1983.

6. Regulatory Guide 1.93, "Availability of Electric Power Sources," U.S. Nuclear Regulatory Commission, December 1974.

7. IEEE-450 [1987], "IEEE Recommended Practice for Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Subsystems," Institute of Electrical and Electronic Engineers.

8. Regulatory Guide 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," February 1977, U.S. Nuclear Regulatory Commission.

9. Regulatory Guide 1.129, "Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Subsystems," U.S. Nuclear Regulatory Commission, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

F 3.8.4 DC Sources—Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for Specification 3.8.3, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC electrical power sources and associated distribution systems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 ar inadvertent draindown of the vessel or a fuel-handling accident.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other Modes of operation (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to DC sources, the requirements established in the TS must be consistent with the GDC related to el[illegible]rical systems, as well as other GDC related to safety-re[illegible] systems, since the DC sources comprise a typical support system.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

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APPLICABLE SAFETY ANALYSES (continued)

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show that a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."}} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4 and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal Shutdown," and 3.9.8, "Residual Heat Removal—Low Water Level."} Therefore, in these conditions, [1 and 2] DC electrical power sources are required to be OPERABLE as support systems.

The DC Sources satisfy Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

LCO 3.8.4.a requires OPERABILITY of the DC electrical power subsystem associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC and DC electrical power sources, as well as the power distribution subsystem itself, will be OPERABLE so that the AC and DC electrical power sources and power distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.4.b requires that they receive DC electrical power from the other [division] DC electrical power subsystem associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.b. Therefore, LCO 3.8.4.b requires this other [division] DC electrical power subsystem to be OPERABLE.

{VS-BWR/6: LCO 3.8.4.c requires OPERABILITY of the [division 3] DC electrical power subsystem associated with the onsite Class 1E power distribution subsystem of LCO 3.8.8.c when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS system [division] are required to be OPERABLE, or both.}

See the Bases of Specification 3.8.3 for additional information on DC electrical power source OPERABILITY and DC electrical power source support and supported systems.

LCO 3.8.4 specifies the minimum number of DC sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]}. It ensures the availability of sufficient DC electrical 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, inadvertent reactor vessel draindown).

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BASES (continued)

LCO (continued)

As described in the previous section, "Applicable Safety Analyses," in the event of an accident during shutdown, the TS are designed to maintain the plant in such a condition that, even with a single failure, the plant will not be in immediate difficulty. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted, provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The DC sources comprise a typical support system.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or 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 draindown 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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

DC electrical power requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.3, "DC Sources—Operating."

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BASES (continued)

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required DC electrical power subsystems inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit's safety systems.

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 the unit's safety systems may be without power.

Required Action A.6 verifies that the Required Actions for supported systems declared inoperable because of the inoperability of one or more DC electrical power subsystems have been initiated and within the same Completion Time as that specified for Required Action A.5.

Required Action A.6 ensures that identified Required Actions associated with supported systems affected by the inoperability of one or more DC electrical power subsystems have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Action for Condition A of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

SR 3.8.4.1 requires performance of all Surveillances required by SR 3.8.3.1 through SR 3.8.3.11. Therefore, see the corresponding Bases for Specification 3.8.3 for a discussion of each SR.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."
2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 Inverters—Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve in being powered from the DC battery source. There is [one] inverter per AC vital bus making a total of [four] inverters. The function of the inverter is to convert DC electrical power to AC electrical power, thus providing an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). The inverters are powered from the [120] V battery source.

[For this facility, specific background details on inverters, such as type, capacity, operating limits, and number and status of spares, are as follows:]

[ ]

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in [the FSAR, Chapter 6, "Engineered Safety Features," and Chapter 15, "Accident Analyses"], assume ESF systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls 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 Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 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 plant. This includes maintaining at least one [division] of the onsite or offsite AC electrical power sources, DC electrical power sources,

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	and associated distribution systems OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power; and b. A worst-case single failure. Inverters satisfy Criterion 3 of the NRC Interim Policy Statement.
LCO	The power distribution subsystems listed in Table B 3.8.7-1 include the inverters. These inverters ensure the availability of AC electrical power for the instrumentation 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. The LCO states that the required inverters shall be OPERABLE. The required inverters for [Division 1] are [Plant Specific: . . . fill in the inverter numbers for [Division 1]]. The required inverters for [Division 2] are [Plant Specific: . . . fill in the inverter numbers for [Division 2]]. {VS-BWR/6: [Division 3] inverters that support the High Pressure Core Spray (HPCS) System or both the HPCS System and other systems are required OPERABLE by LCO 3.8.5 if they are needed to ensure the OPERABILITY OF THE HPCS System and the other systems that they support.} Upon the inoperability of one required inverter, Condition A is entered. Upon the inoperability of two or more required inverters, entry into LCO 3.0.3 is implicitly required. Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is not defeated. If one required inverter is inoperable the possibility of a reactor spurious trip is increased. The [four] battery-powered inverters ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the [4.16 kV] safety buses are de-energized.

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BASES (continued)

LCO (continued)

OPERABILITY is met, as it applies to inverters, provided a correct DC voltage ([120] V) is applied, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. Furthermore, the inverters must be within the manufacturers' specifications for environmental factors such as temperature and humidity.

This LCO is modified by a Note allowing [two] inverters to be disconnected from their associated DC buses for ≤ 24 hours. This allowance is provided to perform an equalizing charge on one battery bank. If the inverters were not disconnected, the resulting voltage condition might damage the inverters energized [from their associated DC buses]. Disconnecting the inverters is allowed provided the associated AC vital buses are energized from their Class 1E constant voltage source transformer and the AC vital buses for other battery banks are energized from the associated inverters connected to their DC buses. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24-hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while taking into consideration the time required to perform an equalizing charge on the battery bank. When utilizing the allowance, if one or more of the provisions is not met (e.g., 24-hour time period exceeded, etc.), LCO 3.0.3 must be entered immediately.

The intent of this Note is to allow only the [one] inverter[s] powered from [its/their] associated DC bus to be disconnected. [Thus, for plants with one battery bank per [division], two inverters may be disconnected. For plants with two battery banks per [division], only one inverter may be disconnected.]

[For this facility, an OPERABLE inverter constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure inverter OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not declare inverters inoperable and their justification are as follows:]

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BASES (continued)

LCO (continued)

[For this facility, the supported systems affected by the inoperability of an inverter and the justification for whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

The inverters are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: 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 {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in the Bases for Specification 3.8.6.

ACTIONS

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

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is [manually] re-energized from its [Class 1E] constant voltage source transformer. Required Action A.1 allows up to 2 hours to perform this task {VS-BWR/6: OR [2 hours] if a [Division 3] inverter is the inoperable inverter}.

{VS-BWR/6: [The [2-hour] Completion Time for an inoperable [division 3] inverter is plant specific. Items to be considered in specifying this Completion Time for a given facility include:

a. The safety function of [Division 3]. If [Division 3] supports other ESF functions in addition to the HPCS function, then the Completion Time for an inoperable [Division 3] inverter shall be [2 hours]; and

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BASES (continued)

ACTIONS (continued)

b. The safety function of the [Division 3] inverter(s):

1. What is its role in mitigating a DBA?

2. What systems does it support?

3. What is its role in mitigating a station blackout?]}

The 2-hour Completion Time is consistent with the 2-hour Completion Time for an inoperable DC bus, and an inoperable AC vital bus (see Specification 3.8.7, "Distribution Systems—Operating"). Required Actions A.2 and A.3 allow 24 hours to fix the inoperable inverter and return it to service {VS-BWR/6: OR [24 hours] if a [division 3] inverter is the inoperable inverter. [The [24-hour] Completion Time is plant specific, and the items listed above should be considered in specifying this time for a given facility]}. The 24-hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). Thus, the probability of a spurious reactor trip is increased. Similarly, the uninterruptible, battery-backed, inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices, because the constant voltage transformer source is more susceptible to voltage drift/degraded voltage than is the inverter source to the AC vital buses.

Required Action A.4 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one inverter have been initiated and within the same Completion Time as that of Required Action A.1.

Required Action A.4 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the inverter have been initiated. This can be accomplished by entering the supported systems' LCOs.

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BASES (continued)

ACTIONS (continued)

[Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Action for Condition A of this LCO.]

[For this facility, the identified support systems' Required Actions are as follows:]

<u>B.1</u>

With one required inverter inoperable <u>AND</u> one or more support or supported features, or both, inoperable associated with the other OPERABLE inverters, or with opposite OPERABLE AC and DC electrical power distribution subsystems, or with opposite OPERABLE DC electrical power subsystems, or all three, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs of the support or supported feature, or both, take into consideration the loss of function situation, then LCO 3.0.3 may not need to be entered.

<u>C.1 and C.2</u>

The plant must be placed in a MODE in which the LCO does not apply if the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

<u>SR 3.8.5.1</u>

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 of the RPS and ESFAS connected to the AC vital buses. The 7-day Frequency takes into account the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	redundant capability of the inverters and other indications available in the control room that will alert the operator to inverter malfunctions.
REFERENCES	None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Inverters—Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for Specification 3.8.5, "Inverters—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources, DC sources, and inverter sources to each AC vital bus during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel-handling accident.

In particular, instrumentation and control capability is powered from the AC vital buses, which are themselves powered by the inverters.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to assure that the plant is operated within its design basis, with regard to AC sources, DC sources, and inverters, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC sources, DC sources, and inverters are typical support systems.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE, or

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications {VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Heat Removal—Low Water Level."} Therefore, in these conditions, [Division 1 and 2] inverter sources to the AC vital buses are required to be OPERABLE as support systems.

The inverters satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

LCO 3.8.6.a requires OPERABILITY of the inverters associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.a. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from the same safety [division] and that all required AC, DC, and inverter sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC, DC, and inverter sources and the distribution subsystem will be capable of fully supporting the non-redundant loads.

When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.6.b requires that they receive inverter support from the other [division] inverters associated with the one [division] of the onsite Class 1E power distribution subsystem of LCO 3.8.8.b. Therefore, LCO 3.8.6.b requires this other [division] inverters to be OPERABLE.

{VS-BWR/6: LCO 3.8.6.c requires OPERABILITY of the [Division 3] inverters associated with the onsite Class 1E power distribution subsystem of LCO 3.8.8.c when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS System [division] are required to be OPERABLE, or both.}

See the Bases for Specification 3.8.5 for additional information on inverter OPERABILITY, and inverter support and supported systems.

LCO 3.8.6 specifies the minimum number of inverters required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or secondary containment]}. It ensures the availability of

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BASES (continued)

LCO (continued)

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, inadvertent reactor vessel draindown).

As described in the previous section, "Applicable Safety Analyses," in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition so that even with a single failure, the plant will not be in immediate difficulty. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE, or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The inverters comprise a typical support system.

APPLICABILITY

The inverters required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or 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 draindown 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 OPERABLE; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

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BASES (continued)

APPLICABILITY (continued)	Inverter requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.5, "Inverters—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required inverters inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the 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 unit's safety systems.

The Completion Time of "Immediately" is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit's safety systems may be without power or powered from a constant voltage source transformer.

Required Action A.6 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one or more inverters have been initiated and within the same Completion Time as that specified for Required Action A.5.

Required Action A.6 ensures that identified Required Actions associated with supported systems affected by the inoperability of one or more inverters have been initiated.

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BASES (continued)

ACTIONS (continued)	This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.] [For this facility, the identified supported systems Required Actions are as follows:]
SURVEILLANCE REQUIREMENTS	SR 3.8.6.1 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 of the Reactor Protection System and Engineered Safety Feature Actuation System 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 will alert the operator to inverter malfunctions.
REFERENCES	1. [Unit name] FSAR, Section [ ], "[Title]." 2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems—Operating

BASES

BACKGROUND

{VS-BW,CE,W,BWR/4: The onsite Class 1E AC and DC electrical power distribution system is divided by [division] into [two] redundant and independent AC and DC electrical power distribution subsystems. Each [divisional] AC and DC electrical power distribution subsystem is comprised of [PLANT SPECIFIC: List the major AC, AC vital, and DC bus names used in Table B 3.8.7-1. For example: 4.16 kVac ENGINEERED SAFETY FEATURE (ESF) buses, 480 Vac load centers, buses, motor control centers, and 120 Vac power distribution panels; 120 Vac vital buses; and 250/125 Vdc buses]. [Two] [divisions] (or subsystems) are required for safety function redundancy; [any one] [division] (or subsystem) provides safety function, but without worst-case single-failure protection.}

{VS-BWR/6: The onsite Class 1E AC and DC electrical power distribution system is divided by [division] into [three] independent AC and DC electrical power distribution subsystems. Each [divisional AC and DC electrical power distribution subsystem is comprised of [PLANT SPECIFIC: List the major AC, AC vital, and DC bus names used in Table B 3.8.7-1. For example: 4.16 kVac ESF buses, 480 Vac load centers, buses, motor control centers, and 120 Vac power distribution panels; 120 Vac vital buses; and 250/125 Vdc buses]. All three [divisions] (or subsystems) are required for safety function redundancy; any two [divisions] (or subsystems) provide safety function, but without worst-case single-failure protection.}

Each [4.16 kV ESF bus] has at least [one separate and independent offsite source of power] as well as a dedicated onsite diesel generator source. Each [4.16 kV ESF bus] is normally connected to a preferred source. During a loss of one offsite power source to the [4.16 kV ESF buses], a [4.16 kV] transfer scheme is accomplished by utilizing a time-delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite emergency power system will supply power to the [4.16 kV ESF buses]. Control power for the [4.16 kV breakers] is supplied from the [Class 1E batteries]. Additional description of this system may be

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BASES (continued)

BACKGROUND (continued)

found in the Bases for Specification 3.8.1, "AC Sources—Operating," and the Bases for Specification 3.8.3, "DC Sources—Operating."

The secondary plant distribution is at [480] V. The [480] V distribution system includes [PLANT SPECIFIC: List items such as emergency buses, load centers, and transformers; the identifying numbers of these items should also be included]. The [480] V load centers from each subsystem are located [in separate rooms in the control building]. Control power for the [480] V breakers is supplied from the [Class 1E batteries], as described in the Bases for Specification 3.8.3, "DC Sources—Operating."

The Class 1E [480] Vac motor control centers and power distribution panels are powered from [PLANT SPECIFIC: Provide bus and/or load center information and nomenclature].

The Class 1E [120] V power distribution panels are powered from [PLANT SPECIFIC: Provide distribution panel information and nomenclature]. All [120] V distribution panels that provide control or instrumentation necessary for operation of safety systems are required to be included in this specification.

The [120] Vac vital buses [2YV1, 2YV2, 2YV3, and 2YV4] are arranged in four load groups and are normally powered from [PLANT SPECIFIC: Provide power path and nomenclature between the inverters and the buses]. The alternate power supply for the vital buses is a [Class 1E constant voltage source transformer] powered from the same [division] as the associated inverter, and its use is governed by LCO 3.8.5, "Inverters—Operating." Each constant voltage source transformer is powered from [PLANT SPECIFIC: Provide power path and nomenclature].

There are {VS-BW,CE,W,BWR/4: [two]} {VS-BWR/6: [three]} independent [125/250] Vdc electrical power distribution subsystems. [PLANT SPECIFIC: Provide power path and nomenclature for the DC power distribution system.]

The list of all required distribution buses is located in Table B 3.8.7-1.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in [FSAR Chapter 6, "Engineering Safety Features," and Chapter 15, "Accident Analyses,"] assume ESF systems are OPERABLE. The AC and DC 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 (RCS) and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 3.6 (Containment Systems).

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one [division] of the onsite or offsite AC electrical power sources, DC electrical power sources, and associated distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst-case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The required AC and DC [divisional] power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC 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. The {VS-BW,CE,W,BWR/4: [Division 1 and 2]} {VS-BWR/6: [Division 1, 2, and 3]} AC and DC electrical power distribution subsystems are required to be OPERABLE.

{VS-BW,CE,W,BWR/4: Maintaining the [Division 1 and 2] AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Either [division] of the AC and DC

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BASES (continued)

LCO (continued)

power distribution system is capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.}

{VS-BWR/6: Maintaining the [Division 1, 2, and 3] AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. [Any two of the three] [divisions] of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.}

OPERABILITY is met, as it applies to AC and DC electrical power distribution subsystems, provided the associated buses, transformers, load centers, motor control centers, and electrical circuits are fully energized to their proper voltages and frequencies. The components of each AC and DC electrical power distribution subsystem must be kept within the manufacturers' specifications for environmental factors such as temperature and humidity.

In addition, breakers must be open between redundant buses to prevent two power sources from being paralleled. The open breakers also preclude unlimited continued operation where a single failure (loss of one source) could cause a loss of two redundant buses. Thus, if two sources are paralleled through redundant distribution buses that are cross-tied, the distribution buses must be considered inoperable. If two redundant buses are powered from the same source, however, only the bus that is not being powered from its normal source shall be considered inoperable.

[For this facility, as a minimum, the following support systems associated with the AC and DC electrical power distribution subsystems governed by LCO 3.8.7 to ensure their OPERABILITY are as follows:]

[For this facility, the supported systems affected by the inoperability of the support systems governed by LCO 3.8.7, and the justification of whether or not each supported system is declared inoperable, are as follows:]

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BASES (continued)

APPLICABILITY

The AC and DC electrical power distribution subsystems are required to be OPERABLE in {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and [illegible] 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.

AC and DC electrical power distribution subsystem requirements for {VS-BW,CE,W: MODES 5 and 6} {VS-GE: MODES 4 and 5} are covered in the Bases for Specification 3.8.8.

A Note has been added to provide clarification that for this LCO, all required AC and DC electrical power distribution subsystems shall be treated as an entity with a single Completion Time.

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except AC vital buses, in <u>one</u> division inoperable the remaining AC electrical power distribution {VS-BW,CE,W,BWR/4: subsystem is} {VS-BWR/6: 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 power distribution {VS-BW,CE,W,BWR/4: subsystem} {VS-BWR/6: 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 a determined amount of time ([ ] hours), not to exceed 8 hours if more than two systems are made inoperable because of the distribution system inoperability.

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BASES (continued)

ACTIONS (continued)

[ ] hours will be a specific number for each specific bus in each specific plant. For a specific bus, [ ] hours is defined as the most limiting Completion Time of all the supported systems that are made inoperable by the inoperability of the bus. Thus, a prior determination must be made to obtain the most limiting Completion Time of all the systems supported by each bus. [ ] does not exceed 8 hours, however, if three or more systems are made inoperable by the bus inoperability.

Note that the equipment referred to is all in one [division] power distribution subsystem.

When equipment governed by LCO 3.8.7 is inoperable in {VS-BW,CE,W,BWR/4: both [divisions]} {VS-BWR/6: two or more [divisions]} and results in loss of functional capability, then LCO 3.0.3 must be immediately entered.

B.1

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours. For an AC vital bus to be considered OPERABLE, it must be powered from its DC-to-AC inverter. An alternate Class 1E constant voltage source may be used if approved for this purpose as stated in the licensing basis of the plant. Requirements imposed on the alternate source are governed by LCO 3.8.5, "Inverters—Operating." The 2-hour Completion Time 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.

{VS-BWR/6: However, if the inoperable AC vital bus is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] AC vital bus supports;

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BASES (continued)

ACTIONS (continued)

furthermore, the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] AC vital bus inoperability. The [2-hour] Completion Time for [Division 3] takes into account the importance to safety of restoring the [Division 3] 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.}

When more than one AC vital bus is inoperable, there is a loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

C.1

With one or more required DC buses in one [division] inoperable the remaining DC electrical power distribution {VS-BW,CE,W,BWR/4: subsystem is} {VS-BWR/6: 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 {VS-BW,CE,W,BWR/4: subsystem} {VS-BWR/6: subsystems} could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours. The 2-hour Completion Time for DC buses is consistent with Regulatory Guide 1.93, "Availability of Electric Power Sources" (Ref. [1]).

{VS-BWR/6: However, if the inoperable DC bus is associated with [Division 3], then continued operation for up to a [2-hour] Completion Time is plant specific and is meant to be the most limiting Completion Time for all systems that a [Division 3] DC bus supports; furthermore, the [2-hour] Completion Time is not to exceed 8 hours if more than two systems are made inoperable because of the [Division 3] DC bus inoperability. The [2-hour] Completion Time for [Division 3] takes into account the importance to safety of restoring the [Division 3] DC bus to OPERABLE status, the redundant capability afforded by the other OPERABLE DC buses, and the low probability of a DBA occurring during this period.}

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BASES (continued)

ACTIONS (continued)

When one or more DC buses are inoperable in more than one AC and DC electrical power distribution subsystem, there is a loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

D.1

With one or more features specified under Condition A, B, or C inoperable in the one [division] of AC and DC electrical power distribution subsystem AND one or more required support or supported features, or both, inoperable associated with the other OPERABLE AC and DC electrical power distribution subsystem(s), or with opposite OPERABLE DC electrical power subsystem(s), or both, there is a loss of functional capability and LCO 3.0.3 must be immediately entered. However, if the LCOs of the support or supported feature, or both, takes into considerat on the loss of function situation, LCO 3.0.3 may not need to be entered.

E.1

With one or more features specified under Condition A, B, or C inoperable in one [division] of AC and DC electrical power distribution subsystem, verify that the Required Actions for those supported systems declared inoperable by the support features governed by LCO 3.8.7 have been initiated and within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting of all the Required Actions for all the supported systems that need to be declared inoperable upon the failure of one or more features specified under Condition E.

Required Action E.1 ensures that those identified Required Actions associated with supported systems affected by the inoperability of the supported features governed by this LCO have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition E of this LCO.]

[For this facility, the identified supported systems Required Actions are as follows:]

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BASES (continued)

ACTIONS (continued)

F.1 and F.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within {VS-BW,CE,W: 6 hours} {VS-GE: 12 hours} and in {VS-BW,CE,W: MODE 5} {VS-GE: MODE 4} within 36 hours. The allowed Completion Times are reasonable, based on operating experience related to the amount of time required to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC 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 and DC electrical power distribution subsystems, and other indications available in the control room that will alert the operator to subsystem malfunctions.

SR 3.8.7.2

This Surveillance verifies that the frequency on the AC vital buses is within limits. [For this facility, the purpose of this Surveillance is as follows:]

The 7-day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems and other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. Regulatory Guide 1.93, "Availability of Electric Power Sources," U.S. Nuclear Regulatory Commission, December 1974.

{This version of Table B 3.8.7-1 is VS-BW,CE,W,BWR/4}

Table B 3.8.7-1 (page 1 of 1)

AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	[Division 1]*	[Division 2]*
AC safety buses	[4160 V]	[ESF Bus] [NB01]	[ESF Bus] [NB02]
	[480 V]	Load Centers [NG01, NG03]	Load Centers [NG02, NG04]
	[480 V]	Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D]	Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D]
	[120 V]	Distribution Panels [NP01, NP03]	Distribution Panels [NP02, NP04]
DC buses	[125 V]	Bus [NK01] from battery [NK11] and charger [NK21]	Bus [NK02] from battery [NK12] and charger [NK22]
		Bus [NK03] from battery [NK13] and charger [NK23]	Bus [NK04] from battery [NK14] and charger [NK24]
		Distribution Panels [NK41, NK43, NK51]	Distribution Panels [NK42, NK44, NK52]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01]	Bus [NN02] from inverter [NN12] connected to bus [NK02]
		Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN04] from inverter [NN14] connected to bus [NK04]

* Each [division] of the AC and DC electrical power distribution system is a subsystem.

(This version of Table B 3.8.7-1 is VS-BW,CE,W,BWR/6)

Table B 3.8.7-1 (page 1 of 1)

AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	[Division 1]*	[Division 2]*	[Division 3]*
AC safety buses	[4160 V]	[ESF Bus] [NB01]	[ESF Bus] [NB02]	[ESF Bus] [NB03]
	[480 V]	Load Centers [NG01, NG0[illegible]]	Load Centers [NG02, NG04]	
	[480 V]	Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D]	Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D]	Motor Control Centers [NG05A, NG05C]
	[120 V]	Distribution Panels [NP01, NP03]	Distribution Panels [NP02, NP04]	Distribution Panels [NP05, NP06]
DC buses	[125 V]	Bus [NK01] from battery [NN11] and charger [NK21]	Bus [NK02] from battery [NK12] and charger [NK22]	Bus [NK05] from battery [NK15] and charger [NK25]
		Bus [NK03] from battery [NN13] and charger [NK23]	Bus [NK04] from battery [NK14] and charger [NK24]	
		Distribution Panels [NK41, NK43, NK51]	Distribution Panels [NK42, NK44, NK52]	Distribution Panel [NK45]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01]	Bus [NN02] from inverter [NN12] connected to bus [NK02]	Bus [NN05] from inverter [NN15] connected to bus [NK05]
		Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN04] from inverter [NN14] connected to bus [NK04]	

* Each [division] of the AC and DC power distribution system is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution System—Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for Specification 3.8.7, "Distribution System—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during shutdown and refueling, as specified in the LCO, ensures that (Ref. 1):

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 draindown of the vessel or a fuel-handling accident.

Although in many cases the FSAR may only address bounding analyses that are typically for power operation, for other modes of operation, the GDC (Ref. 2), among other requirements, are still required to be met. As these GDC are not MODE specific, and as it is a function of the Technical Specifications (TS) to ensure that the plant is operated within its design basis, with regard to distribution systems, the requirements established in the TS must be consistent with the GDC related to electrical systems, as well as with other GDC related to safety-related systems, since the AC and DC electrical power distribution subsystems comprise a typical support system.

In general, when the plant is shut down, the TS requirements ensure that the plant has the capability to mitigate the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

consequences of postulated accidents assuming a single failure, because either:

a. Redundant and independent systems are required to be OPERABLE; or

b. Appropriate administrative measures are established and/or alternate backup systems that can provide functional redundant capability are required to be OPERABLE or put into operation in a period of time commensurate with the accident and the initial conditions considered.

This statement, in general, is reflected in the system LCOs for shutdown MODES of operation.

In addition to the postulated shutdown events directly addressed in the plant FSAR, it is necessary to consider evaluations of plant data that show a large number of events can take place during shutdown. If not mitigated, some of these events can lead to core damage. Typically, the loss of decay-heat removal while there is substantial core decay heat poses a significant likelihood of a release due to a severe core damage accident.

To avoid the consequences of possible accidents during shutdown, different requirements are established according to the design of each plant. So, as far as residual heat removal (RHR) is concerned {VS-BW,CE,W,: the OPERABILITY of the two RHR loops is required in MODES 5 and 6 when the reactor coolant loops are not filled (MODE 5) and when the Reactor Coolant System (RCS) water level above the top of the reactor vessel flange is less than 23 feet (MODE 6). See Specifications 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," and {VS-W: 3.9.7, "Residual Heat Removal and Coolant Circulation—Low Water Level."} {VS-CE: 3.9.5, "Shutdown Cooling and Coolant Circulation—Low Water Level."} {VS-BW: 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."}} {VS-GE: the OPERABILITY of the two RHR shutdown cooling subsystems is always required in MODE 4, and in MODE 5 when RCS water level above the top of the reactor vessel flange is less than 23 feet. See Specifications [VS-BWR/4: 3.4.8,} {VS-BWR/6: 3.4.9,} "Residual Heat Removal—Shutdown," and 3.9.8, "Residual

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	Heat Removal—Low Water Level."} Therefore, in these conditions, [portions of] [Division 1 and 2] AC and DC electrical power distribution subsystems are required to be OPERABLE as support systems. The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	LCO 3.8.8.a requires OPERABILITY of one [division] AC and DC electrical power distribution subsystem. The intent is that all required non-redundant loads, as well as one required load from each required redundant pair of loads, be powered from this safety [division] and that all required AC and DC sources, as well as the distribution subsystem itself, will be OPERABLE so that the AC and DC sources and distribution subsystem will be capable of fully supporting the required loads. When redundant counterpart loads (e.g., the second members of the pair) are required to be OPERABLE, LCO 3.8.8.b requires that they receive power from the [necessary portions of the] other [division] AC and DC electrical power distribution subsystem. Therefore, LCO 3.8.8.b requires [the necessary portions of] this other [division] DC electrical power subsystem to be OPERABLE. {VS-BWR/6: LCO 3.8.8.c requires OPERABILITY of the [division 3] AC and DC electrical power distribution subsystem when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, or when other loads assigned to the HPCS System [division] are required to be OPERABLE, or both.} See the Bases for Specification 3.8.7 for additional information on AC and DC electrical power distribution subsystem OPERABILITY and AC and DC electrical power distribution support and supported systems. LCO 3.8.8 specifies the minimum number of AC and DC electrical power distribution subsystems required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and any time when handling irradiated fuel {VS-GE: [or (continued)

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BASES (continued)

LCO (continued)

moving loads over irradiated fuel in the primary or secondary containment]}. It 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, inadvertent reactor vessel draindown).

As described in the previous section, "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. In some cases, this is accomplished by requiring completely redundant and independent systems to be OPERABLE. In other cases, if justified based on a single plant design, administrative measures may be sufficient to relax the single-failure criterion. Also, an alternative backup system that provides the same functional capability may be substituted provided the backup system is OPERABLE or can be made OPERABLE in sufficient time to mitigate the consequences of an accident during shutdown. When required to be OPERABLE, systems are reliable only if their support requirements are also met. The AC and DC electrical power distribution subsystems comprise a typical support system.

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES {VS-BW,CE,W: 5 and 6} {VS-GE: 4 and 5} and also any time when handling irradiated fuel {VS-GE: [or moving loads over irradiated fuel in the primary or 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 draindown 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 OPERABLE; and

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BASES (continued)

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

AC and DC electrical power distribution subsystem requirements for {VS-BW,CE,W: MODES 1, 2, 3, and 4} {VS-GE: MODES 1, 2, and 3} are covered in Specification 3.8.7, "Distribution System—Operating."

ACTIONS

A.1, A.2, A.3, A.4, A.5, and A.6

With one or more of the required AC and DC electrical power distribution subsystems inoperable, some equipment is not receiving the minimum support it needs. Therefore, it is required to suspend CORE ALTERATIONS, handling of irradiated fuel, {VS-GE: moving of loads over irradiated fuel,} any activities that could potentially result in inadvertent draining of the reactor vessel, and operations involving positive reactivity additions.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions will preclude the occurrence of actions that could potentially initiate the 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 unit's safety systems.

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 unit's safety systems may be without power.

Required Action A.5 verifies that the Required Actions for those supported systems declared inoperable because of the inoperability of one or more AC and DC electrical power distribution subsystems have been initiated and within the same Completion Time as that specified for Required Action A.5.

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BASES (continued)

ACTIONS (continued)

Required Action A.6 ensures that those identified Required Actions associated with supported systems affected by the inoperability of one or more AC and DC electrical power distribution subsystems have been initiated. This can be accomplished by entering the supported systems' LCOs. [Alternatively, the appropriate Required Actions for the supported systems may be listed in the Required Actions for Condition A of this LCO.]

[For this facility, the identified supported systems' Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution system is functioning properly, with all 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 and DC electrical power distribution subsystems, as well as other indications available in the control room that will alert the operator to subsystem malfunctions.

SR 3.8.8.2

This Surveillance verifies that the frequency on the AC vital buses is within limits. [For this facility, the purpose of this Surveillance is as follows:]

The 7-day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, as well as other indications available in the control room that will alert the operator to subsystem malfunctions.

REFERENCES

1. [Unit name] FSAR, Section [ ], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

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 plant procedures which prevent 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 must 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.

One channel of instrumentation is provided to sense the position of the refueling platform, the loading of the refueling platform fuel grapple, and the full insertion of all control rods. Additionally, inputs are provided for the loading of the refueling platform trolley frame-mounted hoist, the loading of the refueling platform monorail-mounted hoist, the full retraction of the fuel grapple, and the loading of the service platform hoist. With the reactor MODE switch in the 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 control rod drive system to prevent withdrawing a control rod.

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BASES (continued)

BACKGROUND (continued)

The refueling platform has two mechanical switches that open before the platform or any of its hoists are physically located over the reactor vessel. All refueling hoists have switches that open when the hoists are loaded with fuel.

The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over 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).

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the FSAR analyses for the control rod removal error during refueling (Ref. 3) and the fuel assembly insertion error during refueling (Ref. 4). These analyses evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. 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 of fuel into the core with any control rod withdrawn or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point [ ] ft [ ] inches from the outside of the reactor core. Considering switch hysteresis and maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel does not reach beyond [ ] ft [ ] inches from the core.

The hoist switches open at a load lighter than the weight of a single fuel assembly in water. A fuel assembly in water weighs [715 (dry)] lb and the hoist switches are set at [680] lb.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

"Refueling Equipment Interlocks" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn or that a rod cannot be withdrawn while a fuel assembly is being loaded.

To prevent these conditions from developing, the all-rods-in, the refueling platform over core position, the refueling platform fuel grapple fuel-loaded, the refueling platform trolley frame-mounted hoist fuel-loaded, the refueling platform monorail-mounted hoist fuel-loaded, the refueling platform fuel grapple fully retracted position, and the service platform hoist fuel-loaded inputs, and the refueling equipment interlocks, are required to be OPERABLE. These inputs and interlocks provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

[For this facility, OPERABLE refueling equipment interlocks and their associated inputs constitute the following:]

[For this facility, the following support systems are required OPERABLE to ensure refueling equipment interlock channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the refueling equipment interlock channels inoperable and their justification are as follows:]

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 required to be OPERABLE during CORE ALTERATIONS with refueling equipment associated with the interlocks.

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BASES (continued)

APPLICABILITY (continued)

In MODES 1, 2, 3, and 4, the reactor pressure vessel (RPV) head is on and CORE ALTERATIONS are not 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 plant must be placed in a condition in which the LCO does not apply. CORE ALTERATIONS 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 CORE ALTERATIONS shall not preclude completion of movement of a component to a safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates that 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 such that the entire channel is tested.

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 plant operations personnel.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

2. [Unit Name] FSAR, Section [ ], "[Title]."

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BASES (continued)

REFERENCES (continued)	3.	[Unit Name] FSAR, Section [ ], "[Title]."
	4.	[Unit Name] FSAR, Section [ ], "[Title]."

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the movement of control rods to reinforce plant procedures which prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod 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 one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit which has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4) and a rod selection signal (from the Reactor Manual Control System).

This specification assures that the performance of the refuel position one-rod-out interlock, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refueling position one-rod-out interlock is explicitly assumed in the FSAR analysis for 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.

The refuel position one-rod-out interlock and adequate SHUTDOWN MARGIN (LCO 3.1.1) prevent criticality by stopping withdrawal of more than one control rod. With one control

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

"Refuel Position One-Rod-Out Interlock" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE.

[For this facility, a refuel position one-rod-out interlock channel is considered OPERABLE when:]

[For this facility, the following support systems are required OPERABLE to ensure refuel position one-rod-out interlock channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the refuel position one-rod-out interlock channels inoperable and their justification are as follows:]

APPLICABILITY

In MODE 5, with the reactor MODE switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1 through 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (RPS) (LCO 3.3.1.1) 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 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

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BASES (continued)

ACTIONS

A.1 and A.2

With one or both channels of the refueling position one-rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

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

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-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 such that the entire channel is tested. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position).

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 fully inserted. The 1-hour Frequency to perform a CHANNEL FUNCTIONAL TEST when any control rod is withdrawn is similarly adequate.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."

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BASES (continued)

REFERENCES (continued)

2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [ ], "[Title]."

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 (CRD) System. During refueling, movement of control rods is limited by the refueling interlocks (LCOs 3.9.1 and 3.9.2) or the control rod block with the reactor MODE switch in the shutdown position (LCO 3.3.2.1).

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 allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. 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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod removal error during refueling in the FSAR (Ref. 2) assumes that the refueling interlocks and adequate SHUTDOWN MARGIN are in place. The analysis for the fuel assembly insertion error during refueling (Ref. 3) assumes all control rods are fully

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

inserted. Thus, all control rods must be fully inserted to ensure an inadvertent criticality does not occur during refueling.

"Control Rod Position" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

All control rods must be fully inserted during applicable refueling conditions to prevent an inadvertent criticality during refueling.

[For this facility, a control rod is considered to be fully inserted when:]

[For this facility, the following support systems are required OPERABLE to ensure that one or more control rods are fully inserted:]

[For this facility, those required support systems which upon their failure do not declare that one or more control rods are not fully inserted and their justification are as follows:]

[For this facility, the supported systems impacted because one or more control rods are not fully inserted and the justification of whether or not each supported system is declared inoperable are as follows:]

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.

An exception to this requirement is allowed (LCO 3.10.6) if fuel is being loaded in an approved spiral reload sequence that does not use a complete set of blade guides. The approved spiral reload sequence typically involves reloading such that fuel is always being loaded on the periphery of

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BASES (continued)

APPLICABILITY (continued)

the fueled zone. During the spiral reloading, all control rods in core cells containing fuel are fully inserted and the control rod in the next cell to be loaded is fully inserted. This minimizes the reactivity insertion of each fuel assembly and the probability of a reactivity excursion.

This specification does not apply in MODES 1, 2, 3, and 4, since the vessel head is in place and refueling operations are not possible.

ACTIONS

A.1 and A.2

With a control rod not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the FSAR. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude the completion of movement of a component to a safe condition.

Required Action A.2 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of one or more control rods not fully inserted within the same Completion Time as that specified for Required Action A.1.

Required Action A.2 ensures that identified Required Actions associated with supported systems impacted because of one or more control rods not fully inserted have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported systems Required Actions are as follows:]

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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	The 12-hour Frequency considers the procedural controls over control rod movement during refueling as well as the redundant functions of the refueling interlocks.
REFERENCES	1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability." 2. [Unit Name] FSAR, Section [ ], "[Title]." 3. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel provides necessary information to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1 and LCO 3.9.2) use the full-in position indication channel to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full position channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this causes the refuel position one-rod-out interlock to 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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod removal error during refueling (Ref. 2) assumes the refueling interlocks are OPERABLE and adequate SHUTDOWN MARGIN is available. The analysis for the fuel assembly insertion error during refueling (Ref. 3) assumes all control rods are fully inserted. 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 withdrawn and that no more than one control rod can be withdrawn at a time.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

"Control Rod Position Indication" satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Each control rod full-in position indication channel must be OPERABLE to provide the required input to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling interlock logic.

[For this facility, the following support systems are required OPERABLE to ensure control rod position indication channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the control rod position indication channel inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a control rod position indication channel and the justification of whether or not each supported system is declared inoperable are as follows:]

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 3.1.2, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor MODE switch in the refuel position, the full-in position indication channels are required to be OPERABLE to ensure the refuel position one-rod-out interlock is OPERABLE.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.3.1, and A.3.2

With one or more full-in position indication channels inoperable, alternative compensating actions must be taken

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BASES (continued)

ACTIONS (continued)

to protect against potential reactivity excursions from new fuel insertions or control rod withdrawals.

The first (and safest) alternative involves immediately suspending CORE ALTERATIONS and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

Suspension of CORE ALTERATIONS and control rod withdrawal shall not preclude completion of the movement of a component to a safe condition.

The second alternative requires immediately initiating actions to fully insert the control rod(s) and disarm the drive(s) associated with the inoperable full-in position indicator(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.

An inoperable full-in channel may be bypassed to allow refueling operations to proceed. Under this condition, an alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication). If all fuel is removed from a core cell, the full-in position indication may be bypassed since the control rod may be withdrawn and the position indication is not required to be OPERABLE.

Required Action A.1 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of the inoperability of one or more control rod position indication channels within the same Completion Time as that specified for other Required Actions in Condition A.

Required Action A.1 ensures that identified Required Actions associated with supported systems impacted because of the inoperability of one or more Control Rod Position Indication channels have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported systems Required Actions are as follows:]

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels are verified to be OPERABLE when they are available for all fully inserted control rods.

The 24-hour Frequency 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 of control rods not fully inserted.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [ ], "[Title]."

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 (RPS), 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.

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 SHUTDOWN MARGIN (LCO 3.1.1), the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), the average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analyses for the control rod removal error during refueling (Ref. 2) and the fuel assembly insertion error during refueling (Ref. 3) evaluate the consequences of control rod withdrawal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides backup protection should a prompt reactivity excursion occur.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	"Control Rod OPERABILITY—Refueling" satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if it is capable of being automatically inserted upon receipt of a scram signal, including the scram accumulator pressure > [940] psig. [For this facility, the following support systems are required OPERABLE to ensure control rod OPERABILITY during Refueling:] [For this facility, those required support systems which upon their failure do not declare the control rods inoperable and their justification are as follows:]
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 LCOs 3.1.2, 3.1.3, 3.1.4, and 3.1.5. During MODES 3 and 4, control rods are only allowed to be withdrawn under special operations LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown," and LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," which 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 ensures the shutdown and scram capabilities are not adversely affected.

(continued)

BASES (continued)

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 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 [940] psig.

The 7-day Frequency considers equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights which indicate low accumulator charge pressures.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section VI, GDC 26, "Reactivity Control System Redundancy and Capability."
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies within containment, with irradiated fuel in containment, requires a minimum water level of [23] ft above the top of the reactor vessel flange. During refueling, this maintains a sufficient water level in the containment, refueling cavity, refueling canal, fuel transfer canal, and spent fuel pool. Sufficient water is necessary to retain iodine fission-product activity in the water in the event of a fuel-handling accident (Refs. 1 and 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, the water level in the refueling cavity and refueling canal is an initial-condition design parameter in the analysis of a fuel-handling accident in containment postulated by Regulation Guide 1.25 (Ref. 1). A minimum water level of [23] ft (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) 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 [23] ft and a minimum decay time of 100 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. 4).

"RPV Water Level" satisfies Criterion 2 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

A minimum water level of [23] ft 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.

[For this facility, the following support systems are required OPERABLE to ensure RPV water level indication channel OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the RPV water level indication channel inoperable and their justification are as follows:]

APPLICABILITY

Within the containment, LCO 3.9.6, "Reactor Pressure Vessel Water Level," is applicable when irradiated fuel assemblies are seated within the RPV and when fuel assemblies are being moved over or 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 over or 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 3.7.9.

ACTIONS

A.1

If the water level is < [23] ft above the top of the RPV flange, all operations involving movement of fuel assemblies shall be suspended immediately to ensure that a fuel-handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement to a safe position.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

In the event that the required RPV water level indicatio[n] channels are found inoperable, the RPV water level indication channel is considered to be not within limits a[nd] Required Action A.1 applies.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of [23] ft 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 above the top of the RPV flange 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.

REFERENCES

1. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel-Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, March 23, 1972.
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. NUREG-0800, "Standard Review Plan," Section 15.7.4, "Radiological Consequences of Fuel-Handling Accidents," U.S. Nuclear Regulatory Commission.
4. Title 10, Code of Federal Regulations, Part 20, Section 20.101(2), "Radiation Dose Standards for Individuals in Restricted Areas."

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 two shutdown cooling loops of the RHR System can provide the required decay-heat removal. Each loop consists of two motor-driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.2). 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 ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to inadequate cooling of the reactor fuel because of the resulting loss of coolant in the RPV. The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. One train of the RHR System is required to be operational to prevent this challenge.

The RHR System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Only one RHR subsystem is required to be OPERABLE, and in operation in MODE 5 with the water level $\geq$ [23] ft above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay-heat-removal capability.

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BASES (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. In MODE 5, the RHR cross-tie valve is not required to be closed; thus, the valve may be opened to allow pumps in one loop to discharge through the opposite loop's heat exchanger to make a complete subsystem.

[For this facility, an RHR subsystem in operation constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure RHR System OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the RHR System inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of an RHR System and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

One RHR subsystem must be OPERABLE and in operation in MODE 5, with the water level ≥ [23] feet 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," Section 3.5, "Emergency Core Cooling System and Reactor Core Isolation Cooling," and Section 3.6, "Containment Systems." RHR System requirements in MODE 5 when the water level is < [23] ft above the RPV flange are given in LCO 3.9.8.

ACTIONS

A.1, A.2, A.3, A.4, A.5 and A.6

If no RHR subsystem is OPERABLE or in operation, actions shall be taken immediately to suspend operations involving an increase in reactor decay-heat load. Also, actions shall be taken to restore one RHR subsystem to OPERABLE status and operation within 15 minutes. The 15-minute Completion Time is sufficient for an operator to initiate corrective action.

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BASES (continued)

ACTIONS (continued)

In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. Actions must continue until at least one RHR subsystem is restored to OPERABLE status and to operation.

If at least one RHR subsystem is not restored to OPERABLE status within 15 minutes, 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 System (SGTS) 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 on 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.

Required Action A.6 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of the inoperability of required RHR subsystems within the same Completion Time as that specified for other Required Actions in Condition A.

Required Action A.6 ensures that identified Required Actions associated with supported systems impacted because of the inoperability of required RHR subsystems have been initiated. This can be accomplished by entering the supported systems LCOs or independently as a group of Required Actions needed to be initiated every time Condition A is entered. [For this facility, the identified supported system Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This surveillance verifies that the RHR subsystem is OPERABLE, in operation, and circulating reactor coolant.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	The 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 two shutdown cooling loops of the RHR System can provide the required decay-heat removal. Each loop consists of two motor-driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.2). The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to inadequate cooling of the reactor fuel due to the resulting loss of coolant in the reactor pressure vessel (RPV). The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. Two trains of the RHR System are required to be OPERABLE and one in operation to prevent this challenge.

Although the RHR System does not meet a specific criterion of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a technical specification.

LCO

In MODE 5, with the water level < 23 ft above the RPV flange, both RHR subsystems must be OPERABLE. Additionally, one subsystem of RHR must be in operation.

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BASES (continued)

LCO (continued)

An OPERABLE RHR subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. To meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. In MODE 5, the RHR cross-tie valve is not required to be closed; thus, the valve may be opened to allow pumps in one loop to discharge through the opposite loop's heat exchanger to make a complete subsystem.

[For this facility, an RHR subsystem in operation constitutes the following:]

[For this facility, the following support systems are required OPERABLE to ensure RHR System OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the RHR System inoperable and their justification are as follows:]

[For this facility, the supported systems impacted by the inoperability of a RHR System and the justification of whether or not each supported system is declared inoperable are as follows:]

APPLICABILITY

Two RHR subsystems are required to be OPERABLE, and one must be in operation in MODE 5 when the water level is < [23] ft 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"; Section 3.5, "Emergency Core Cooling System and Reactor Core Isolation Cooling"; and Section 3.6, "Containment Systems." RHR System requirements in MODE 5 when the water level is ≥ [23] ft above the RPV flange are given in LCO 3.9.7.

ACTIONS

A.1 and A.2

If one RHR subsystem is inoperable or not in operation, actions shall be taken and continued until the RHR subsystem is restored to OPERABLE status and operation or a water level ≥ [23] ft is established above the RPV flange.

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BASES (continued)

ACTIONS (continued)

Raising the water level will result in conditions that only require a single RHR subsystem to be OPERABLE and in operation (LCO 3.9.7). A Completion Time of 15 minutes is allowed for an operator to initiate corrective action.

B.1, B.2, B.3, B.4, and B.5

If no RHR subsystem is OPERABLE or is not in operation, actions shall be initiated immediately and continued without interruption to restore one RHR subsystem to OPERABLE status and operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR subsystems and one operating RHR subsystem should be accomplished expeditiously.

With no RHR subsystem OPERABLE or in operation, alternate actions shall have been initiated within 15 minutes under Condition A to establish ≥ [23] ft of water above the top of RPV flange. Furthermore, when the LCO cannot be fulfilled, alternate decay-heat removal methods, as specified in the plant's Abnormal and Emergency Operating Procedures, should be implemented. These 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 safest and most prudent choice, based upon plant conditions.

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 System 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, the surveillance may need to be performed to restore the

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BASES (continued)

ACTIONS (continued)

component to OPERABLE status. Actions must continue until all required components are OPERABLE.

Required Action B.5 initiates action to verify that the Required Actions have been initiated for the supported systems declared inoperable because of the inoperability of required RHR subsystems within the same Completion Time as that specified for other Required Actions in Condition B.

Required Action B.5 ensures that identified Required Actions associated with supported systems impacted because of the inoperability of required RHR subsystems have been initiated. This can be accomplished by entering the supported systems LCOs, or independently as a group of Required Actions needed to be initiated every time Condition B is entered. [For this facility, the identified supported systems Required Actions are as follows:]

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This surveillance verifies that one RHR subsystem is OPERABLE, in operation, and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay-heat-removal capability. In addition, this surveillance verifies that the other RHR subsystem is OPERABLE. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystems in the control room.

REFERENCES

None.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic (ISLH) Testing Operation

BASES

BACKGROUND

The purpose of this MODE 4 special operations LCO is to give flexibility and to obtain a good inspection in performing certain reactor coolant pressure tests when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures ≥ 200°F (normally corresponding to MODE 3).

Inservice hydrostatic 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. Recirculation 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. 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 (at a given pressure) increases. Periodic updates to the RPV P/T limit curves are performed as necessary, based upon 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 above 200°F.

The hydrostatic test requires increasing pressure to [%] of design pressure (1250 psig) or [psig], and because of the expected increase in reactor vessel fluence, the minimum allowable vessel temperature per LCO 3.4.9 is increased to [°F]. This increase to [%] of design pressure does not exceed the Safety Limit of 1375 psig.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion for permitting irradiated fuel to be in the reactor while allowing hydrostatic testing to be performed is that the offsite dose criteria of [10 CFR, Title] be met. The leak break frequency of the reactor vessel pressure boundary during the performance of a hydrostatic test has been categorized as a [ ] faulted condition (Ref. 2). The evaluation of the potential fission product release and dose to the offsite public due to potential fuel melt as a result of dryout from a leak or break event during a hydrostatic test has been approved by the commission (Ref. 3).

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing when the reactor coolant temperature is above 200°F effectively provides an exception to MODE 3 requirements including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling System (ECCS). Since the hydrostatic or leak tests are performed water solid, at 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 LCO 3.4.7 ("Reactor Coolant Specific Activity") limits is 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 (Ref. 3). The consequences of a steam leak under pressure testing conditions with the secondary containment OPERABLE will be conservatively bounded by the consequences of the [postulated main steam line break (MSLB) outside of primary containment] accident analysis described in Reference 4. The Reference 3 analysis of the postulated MLSB outside of primary containment is bounding because [explain]. 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 system to operate. The capability of the low pressure coolant injection and core spray subsystems as

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

required in MODE 4 by LCO 3.5.2 would be more than adequate to keep the core flooded under this low decay heat load condition (Ref. 3). 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.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. Operation at reactor coolant temperatures > 200°F 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 > 200°F 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. [For this facility, the MODE 4 applicable LCOs are as follows:] This special operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "N/A." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purpose of performing either an inservice leak or hydrostatic test.

In order for this special operations LCO to accomplish its objective, the SRs for LCO 3.6.4.1, LCO 3.6.4.2, LCO 3.6.4.3, and LCO 3.7.2 must be met and the following additional support systems must be OPERABLE [list].

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BASES (continued)

LCO (continued)

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 which are in effect immediately prior to and immediately after this operation.

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of the ISLH Tests so that these operations can be considered as in MODE 4 even though the reactor coolant temperature is > 200°F. The additional requirement for secondary containment OPERABILITY per the imposed MODE 3 requirements provides conservatism in the response of the facility to any event which may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements are entered and complied with immediately. Required Action A.1 has been modified by a Note which clarifies the intent of another LCO's [List] Required Action to be in MODE 4, including reducing the average reactor coolant temperature to ≤ 200°F.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action A.2.2 are alternate Actions that can be taken instead of Required Action A.1 and are provided to restore compliance with the normal MODE 4 requirements and thereby exit this Special Operation LCO's Applicability. Activities which 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 24-hour Completion Time 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 of [°F] to ≤ 200°F with normal cooldown procedures.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required .o have their Surveillances met to establish that this LCO is being met.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

2. [Unit Name] FSAR, Section [15], "[Title]."

3. [Unit Name] FSAR, Section [ ], "[Title]."

4. [Unit Name] FSAR, Section [ ], "[Title]."

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 periodic testing in MODES 3, 4, and 5 of various interlocks and calibrations by imposing administrative controls on plant operations.

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 relays 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 OR HOTSTANDBY—Selects NMS scram function for low neutron flux level operation (intermediate range 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, scram discharge volume trip bypass, refueling interlocks, suppression pool makeup, and main steam isolation valve isolations.

Operation of the reactor mode switch from one position to another may be required to confirm certain aspects of these various interlocks during periodic tests and calibrations.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to preclude fuel failure by precluding reactivity excursions or core criticality. The rod scram and interlock functions of the shutdown and refuel positions normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions which could potentially result in fuel failure. Interlock testing which requires moving the reactor mode switch to other positions (run, or hot standby or startup) while in MODES 3, 4, or 5 requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted 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 unintentional rod withdrawal or rod drop, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). [Discuss main accident events analyzed.]

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 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, LCO 3.10.4, and LCO 3.10.7) without meeting this LCO or its ACTIONS. If any testing is performed which involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, it 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 per Table 1.1.-1, all control rods are fully 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. Since rod withdrawal could inadvertently occur while in MODES 3 or 4 with the reactor mode switch in hot standby or

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BASES (continued)

LCO (continued)

startup or run position, the rod block is [explain why rod block is not in effect]. 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 can be withdrawn under the refuel position one-rod-out interlock (LCO 3.9.2). The refueling equipment interlocks (LCO 3.9.1) 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 operations. The additional controls of administratively not permitting other core alterations will adequately ensure that the reactor does not become critical during these tests.

To ensure the control rods are fully inserted and no other CORE ALTERATIONS are in progress, the SRs of this LCO must be met and the following additional support systems must be operable [list].

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 plant 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 calibration 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)

BASES (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. 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 operating in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch shall 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 action is not applicable in MODES 3 and 4 since only the shutdown position is allowed in these modes. The 1-hour Completion Time for Required Action A.2, Required Action A.3.1, and Required Action A.3.2 provides sufficient time to normally insert the control rods based on operating experience and is acceptable given that all operations which 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 which are not in effect due to the testing in progress are adequately compensated for by the special operations LCO requirements. The administrative controls, to ensure that the operational requirements continue to be met, are to be periodically verified. The Surveillances performed at the [12-hour] and [24-hour] Frequencies are intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these special operations LCO requirements.

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [7], "[Title]."
2. [Unit Name] FSAR, Section [7], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single 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 for testing while in hot shutdown by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions due to the other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances will arise while in MODE 3 which present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This special operations LCO provides the appropriate additional controls to allow a single control rod 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 in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures which prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks which prevent inadvertent criticalities during refueling.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Alternate backup protection can be obtained by assuring that a five-by-five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODES 3 and 4 operation 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 and LCO 3.10.4) without meeting this special operations LCO or its ACTIONS. However, if a single control rod 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, required by this special operations LCO, will ensure that only one control rod can be withdrawn.

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod 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 in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal, the possibility of criticality on withdrawal of this control rod is sufficiently precluded so as not to require the scram capability of the withdrawn control rod.

In order for the control rods to be considered fully inserted and the control rods in the five-by-five array to be disarmed, the SRs of this LCO must be met and the following support systems must be OPERABLE [List].

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod

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BASES (continued)

APPLICABILITY (continued)	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. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1 and LCO 3.9.5) or the added administrative controls in Item D.2 of this special operations LCO minimize potential reactivity excursions.

ACTIONS

A.1

If one or more of the LCOs or 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. Required Action A.1 has been modified by a Note which 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 by returning the reactor mode switch to the shutdown position.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Actions that can be taken instead of Required Action A.1 and are provided to restore compliance with the normal MODE 3 requirements, thereby exiting this special operations LCO's Applicability. All insertable control rods are required to be fully inserted. Placing the reactor mode switch in the shutdown position will ensure all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The 1-hour Completion Time for both of these Required Actions 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	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 preclude the possibility of criticality. Also, SR 3.10.3.3 verifies that all other control rods are fully inserted. The 24-hour Frequency is acceptable because of the administrative controls on control rod withdrawal, the protection afforded by the LCOs involved, and hardwire interlocks which preclude additional control rod withdrawals.
REFERENCES	1. [Unit Name] FSAR, Section [15], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single 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 for testing 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 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 drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

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 in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (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. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

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 assuring that

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

a five-by-five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing a CRD because this removal renders the withdrawn control rod incapable of being scram.

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 3 and 4 operations 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 and LCO 3.10.3) without meeting this special operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this special operations LCO applied.

The refueling interlocks of LCO 3.9.2 required by this special operations LCO 3.10.4 will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4 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 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 when the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal. This precludes the possibility of criticality upon withdrawal of this control rod, including its CRD.

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BASES (continued)

LCO (continued)

Additionally, in order for this special operations LCO to be met, the associated SRs must be met and the following support systems must be OPERABLE [List].

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. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1 and LCO 3.9.5) or added administrative controls in Item C.2 of this special operations LCO provide mitigation of potential reactivity excursions.

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the LCOs or 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 exemptions allowed in this special operations LCO. Required Action A.1 has been modified by a Note which clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods to also include exiting this special operations Applicability by returning the reactor mode switch to the shutdown position.

Required Actions A.2.1 and A.2.2 are specified based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, the ACTIONS require the control rod be inserted and the reactor mode switch placed in the shutdown position. The 1-hour Completion Time for Required Actions A.2.1 and A.2.2 provides sufficient time to normally insert the control rods.

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BASES (continued)

ACTIONS (continued)

B.1, B.2.1, and B.2.2

If one or more of the LCOs or requirements of this special operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must be immediately suspended. If the CRD has been removed such that the control rod is not insertable, the ACTIONS require the most expeditious action be taken to either 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 (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"; LCO 3.9.4, "Control Rod Position Indication"; LCO 3.3.1.1, "Reactor Protection System Instrumentation"; Functions 1.a, 1.b, 2.a, 2.e, 11, and 12 of Table 3.3.1.1-1 for MODE 5; LCO 3.3.8.2, MODE 5, "Reactor Protection System Electric Power Monitoring;" and LCO 3.9.5, "Control Rod Operability—Refueling") 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 provides assurance that those control rods whose position indication instrumentation is inoperable 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 hardwire interlocks to preclude an additional control rod withdrawal.

REFERENCES

1. [Unit Name] FSAR, Section [15], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 special operations LCO is to permit the removal of a single 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 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 one-rod-out interlock will not allow the withdrawal of a second control rod.

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 to be removed from a core cell 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 One-Rod-Out Interlock." The CRD removal also 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").

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BASES (continued)

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 in the FSAR (Ref. 1) demonstrate that functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will preclude unacceptable reactivity excursions.

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. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod 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 one-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).

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 assuring 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).

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 5 operation with any of the following LCOs, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or

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BASES (continued)

LCO (continued)

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 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 3.3.1.3, 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 one-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). Assuring that the five-by-five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection which LCO 3.3.1.1, "Reactor Protection System Instrumentation," and LCO 3.9.2 would have otherwise provided.

The exemption granted in this special operations LCO to assume that the withdrawn control rod is the highest worth control rod 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 may not be the highest worth control rod).

[For this facility, an OPERABLE control rod block constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure control rod block OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring control rod block inoperable and their justification are as follows:]

APPLICABILITY

MODE 5 operations are controlled by existing LCOs. The allowance to comply with this special operations LCO in lieu

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BASES (continued)

APPLICABILITY (continued)

of the ACTIONS of LCO 3.3.1.1, LCO 3.3.1.3, 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 reduce the potential for reactivity excursions.

ACTIONS

A.1, A.2.1, and A.2.2

If 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 3.3.1.3, 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 that these ACTIONS be implemented in a very short time and carried through in an expeditious manner either to restore the CRD and insert its control rod or to restore compliance with this special operations LCO.

In the event that the control rod block is found inoperable, Required Action A.1, Required Action A.2.1, and Required Action A.2.2 apply.

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 other control rods are fully inserted is required to assure the SDM is within limits. Verification the local five-by-five array of control rods 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 provides assurance that those control rods whose position indication instrumentation is inoperable are fully inserted. 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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	met. Verification that no other CORE ALTERATIONS are being made is required to assure 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 hardwire interlock to block an additional control rod withdrawal.
REFERENCES	1. [Unit Name] FSAR, Section [5], "[Title]."

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 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 rod 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 one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This special operations LCO establishes the necessary administrative controls to allow bypassing the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SHUTDOWN MARGIN (SDM) will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	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. The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.
LCO	As described in LCO 3.0.8, compliance with this special operations LCO is optional. MODE 5 operation with either LCO 3.9.3, 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. 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 loaded before loading fuel. Additionally, in order for this LCO to be met, the associated SRs must be met and the following support systems must be OPERABLE [list].
APPLICABILITY	MODE 5 operations are controlled by existing LCOs. The exemption from other LCO requirements (e.g., the ACTIONS of LCO 3.9.4) allowed by this special operations LCO is appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

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BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

If the requirements of this special operations LCO are not met, the immediate implementation of these Required Actions restore 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 exemptions 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 ACTIONS be implemented in a very short time and carried through in an expeditious manner to either restore the affected CRDs and insert their control rods, or 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. [Unit Name] FSAR, Section [15], "[Title]."

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 3.3.2.1) such that only the specified control rod sequences in LCO 3.1.6 and relative positions 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 control rod drop accident (CRDA). 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 include SHUTDOWN MARGIN 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 exemption 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 CRDA are summarized in References 1 and 2. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analysis of References 1 and 2 may not be preserved, and therefore special CRDA analyses were performed to demonstrate that these special sequences will not result in unacceptable consequences should a CRDA occur during the testing. The safety analysis for the special CRDA analysis that demonstrates acceptable consequences is in Reference 3.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	These special CRDA analyses are as follows [explain]. These analyses address the specific testing being performed. The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.
LCO	As described in LCO 3.0.8, 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, and no exemptions 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 are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified per SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator or other qualified member of the technical staff. These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1. Additionally, in order that this LCO be met, the associated SRs must be met, and the following support systems must be OPERABLE [list].
APPLICABILITY	Control rod testing during 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, LCO 3.2.2, and LCO 3.3.2.1. With THERMAL POWER less than or equal to the LPSP of the RWM, the provisions of this special

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BASES (continued)

APPLICABILITY (continued)

operations LCO are necessary to perform special tests which are not in conformance with the prescribed sequences of LCO 3.1.6. During MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with special operations LCO 3.10.3 or special operations LCO 3.10.4, 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 one-rod-out interlock (LCO 3.9.2) and scram functions (LCO 3.3.1.1 and LCO 3.9.5) or added administrative controls prescribed in the applicable special operations LCOs provide mitigation of potential reactive excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence, the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer exempted and appropriate actions are to be taken 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

With the special test sequence not programmed into the RWM, a second licensed operator or other qualified member of the technical staff is required to verify conformance with the approved sequence for the test. (Note: a member of the technical staff is considered to be qualified if he possesses skills equal to a licensed operator in the following areas [list].) This verification must be performed during control rod movement to prevent deviations from the specified sequence. This Surveillance demonstrates compliance with Required Action C.1 of LCO 3.3.2.1. A Note is added to indicate that this surveillance does not need to be performed if SR 3.10.7.2 is satisfied.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.7.2

With the RWM used to provide conformance to the special test sequence, the test sequence must be verified to be correctly loaded into the RWM prior to control rod movement. This Surveillance demonstrates compliance with SR 3.3.2.1.8, thereby demonstrating that the RWM is OPERABLE. A Note is added to indicate that this Surveillance does not need to be performed if SR 3.10.7.1 is satisfied.

REFERENCES

1. NED-24011-P-A-9-US, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Section S.2.2.3.1, September 1988.

2. [Unit Name] FSAR, Chapter [ ], "[Title]."

3. [Unit Name] FSAR, Chapter [ ], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN Test (SDM)—MODE 5

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 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 the 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.

[Provide a discussion of how the SDM test is done, including the use of in sequence criticals and, in some cases, not following the approved banked position withdrawal sequence (BPWS) (see LCO 3.10.7, "Control Rod Testing—Operating," which allows exception to the BPWS). LCO 3.10.7 also requires that the special sequences (outside the BPWS) must be programmed into the Rod Worth Minimizer (RWM) or be verified by a second licensed operator.]

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion for performing the SDM test in MODE 5 is that the reactor remain subcritical. Subcriticality during the planned test is maintained by requiring the control rod block instrumentation to be OPERABLE, the RWM control sequence to be programmed with the SDM test sequence or be verified by a second licensed operator, all out-of-sequence withdrawals to be in the notch out mode, and [explain].

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawals with the reactor mode switch in the startup or hot standby position while in MODE 5 is provided by the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1), average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and control rod block instrumentation (LCO 3.3.2.1). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

CRDA 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. For sequences developed for the SDM testing, the control rod patterns assumed in the safety 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 and, therefore, special CRDA analyses are required to demonstrate the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. The safety analysis for the special CRDA analyses that demonstrates acceptable consequences is in Reference 3. These special CRDA analyses are as follows [explain]. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as wel postulated accidents within the bounds of the app e safety analyses (Refs. 1, 2, and 3). In add. to the added requirements for the RWM, IRM, and APRM, an ner requirement is invoked for out-of-sequence withdrawals, namely, the notch out mode is specified. Requiring the notch out mode limits withdrawal steps to [explain] which limits inserted reactivity to [explain].

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The components, process variables, and LCOs addressed by special operation LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, 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, the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.2.1, function 2, MODE 2), or must be 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 [BPWS] specified in LCO 3.1.6 (i.e., out-of-sequence control rod withdrawals) must be made in the individual notched withdrawal mode to minimize the potential reactivity insertion associated with each movement. 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 or hot standby position such that the SDM tests may be performed while in MODE 5. In addition to the requirements of this LCO, the normally required MODE 5 applicable LCOs [list] must be met.

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 lead 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.

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BASES (continued)

ACTIONS

A.1

With 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.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1 and SR 3.10.8.2

As indicated by the notes, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, function 2, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied either according to the applicable Frequencies or the proper movement of control rods must be verified. This latter verification (i.e., SR 3.10.9.2) 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 3.10.8.3

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.

(continued)

BASES (continued)

REFERENCES

1. NEDE-24011-P-A-9-US, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Section S.2.2.3.1, September 1988.
2. [Unit Name] FSAR, Section [ ], "[Title]."
3. [Unit Name] FSAR, Section [ ], "[Title]."

B 3.10 SPECIAL OPERATIONS

B 3.10.9 Recirculation Loops—Testing

BASES

BACKGROUND

The purpose of this special operations LCO in MODES 1 and 2 is to allow either PHYSICS TESTS or the Startup Test Program to be performed with fewer than two recirculation loops 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, "Recirculation Loops—Operating," requires that one or both recirculation loops 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 in single loop operation with the reactor critical.

APPLICABLE SAFETY ANALYSES

The acceptance criterion for allowing testing with the recirculation loops not operating in MODES 1 and 2 is that postulated accidents will not exceed their allowable consequences [Explain].

The operation of the Reactor Coolant Recirculation System is an initial condition assumed in the design basis loss-of-coolant accident (LOCA) (Ref. 3). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the postulated accident. During PHYSICS TESTS at or below [5]% of RATED THERMAL POWER (RTP), or limited testing during the Startup Test Program for the initial cycle, the decay heat in the reactor is sufficiently low such that the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important (Ref. 4). In addition, the probability of a Design Basis Accident (DBA) or other accidents occurring during the limited time allowed at natural circulation or in single loop operation is low.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Additionally, other postulated accidents which are affected by the operation of the recirculation loops have been determined to be acceptable during these tests or the Startup Test Program as analyzed in Reference 5 [Explain this other analysis].

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

LCO

As described in LCO 3.0.8, compliance with this special operations LCO is optional. However, to perform testing at natural circulation conditions or with a single operating loop, operations must be limited to those tests defined in the Startup Test Program or approved PHYSICS TESTS performed at $\leq$ [5]% of RTP. To minimize the probability of an accident while operating at natural circulation conditions or with one operating loop, the duration of these tests is limited to $\leq$ 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.

[For this facility, an OPERABLE THERMAL POWER instrumentation constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure THERMAL POWER instrumentation OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the THERMAL POWER instrumentation inoperable and their justification are as follows:]

APPLICABILITY

This special operations LCO may only be used while performing testing at natural circulation conditions or while operating with a single loop, as may be required as part of the Startup Test Program or during low power PHYSICS TESTS. Additional requirements during these tests to limit

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(continued)

BASES (continued)

APPLICABILITY (continued)

the time at natural circulation conditions reduces the probability that a DBA may occur with both recirculation loops not in operation. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With the testing performed at natural circulation conditions or with a single operating loop 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 both recirculation loops to be in operation. The 1-hour Completion Time provides sufficient time to normally insert the withdrawn control rods.

B.1

With the requirements of this LCO not met for reasons other than those specified in Condition A (i.e., low power PHYSICS TESTS exceeding 5% of RTP, or unapproved testing at natural circulation), the reactor mode switch should immediately be placed in the shutdown position. This results in a condition that does not require both recirculation loops to be in operation. The action to immediately place the reactor mode switch in the shutdown position is to prevent unacceptable consequences from an accident initiated from outside the analysis bounds. Also, operation beyond authorized bounds should be terminated upon discovery.

In the event that the required THERMAL POWER instrumentation is found inoperable, the Required Action B.1 applies.

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

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(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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. [Unit Name] FSAR, Section [14], "[Title]."

2. Title 10, Code of Federal Regulations, Part 50.59, "Changes, Tests, and Experiments."

3. [Unit Name] FSAR, Section [6], "[Title]."

4. [Unit Name] FSAR, Section [ ], "[Title]."

5. [Unit Name] FSAR, Section [ ], "[Title]."

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 rejection 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 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 coolant injection (LPCI) mode of the RHR System is one of the ECCS subsystems assumed to function during a LOCA. With reactor power $\leq$ 1% of RATED THERMAL POWER (RTP) (equivalent to all OPERABLE intermediate range monitor (IRM) channels $\leq$ 25 or 40 divisions of full scale on range 7) and reactor coolant temperature < 200°F, the stored energy in the reactor core and coolant system is very low and a reduced complement of ECCS systems can provide the required core cooling, thereby allowing operation with one RHR subsystem in the shutdown cooling mode (Ref. 1).

The components, process variables, and LCOs addressed by special operations LCOs satisfy Criteria 1, 2, and 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

As described in LCO 3.0.8, 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 accomplished with one RHR subsystem aligned in the shutdown cooling mode to maintain reactor coolant temperature < 200°F. Under these conditions, the THERMAL POWER must be maintained below 1% of RTP (equivalent to all OPERABLE IRM channels ≤ 25 or 40 divisions of full scale on range 7) and the reactor coolant temperature must be < 200°F. This special operations LCO then allows changing the LPCI OPERABILITY requirements. In addition to the requirements of this LCO, the normally required MODE 2 applicable LCOs must also be met.

[For this facility, an OPERABLE IRM channel and reactor coolant temperature instrumentation constitutes the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure IRM channel and reactor coolant temperature instrumentation OPERABILITY:]

[For this facility, those required support systems which upon their failure do not require declaring the IRM channels and reactor coolant temperature instrumentation INOPERABLE and their justification are as follows:]

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 which could require operation of both RHR subsystems in the LPCI mode of operation. Operations in all other modes are unaffected by this LCO.

(continued)

BASES (continued)

ACTIONS

A.1

With the requirements of this LCO not met (i.e., any OPERABLE IRM channel > 25 or 40 divisions of full scale on range 7, or reactor coolant temperature ≤ 200°F) 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 LPCI mode of operation. This action may restore compliance with the requirements of this special operations LCO or may result in placing the plant in either MODE 3 or MODE 4.

In the event that the required IRM channels or reactor coolant temperature instrumentation is found inoperable, Required Action A.1 applies.

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 LPCI mode of operation. The 1-hour Frequency provides frequent checks of these LCO requirements during the training startup.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Title]."

APPENDIX A

Acronyms

The following acronyms are used, but not defined, in the Standard Technical Specifications:

AC	alternating current
CFR	Code of Federal Regulations
DC	direct current
FSAR	Final Safety Analysis Report
LCO	Limiting Condition for Operation
SR	Surveillance Requirement
GDC	General Design Criteria or General Design Criterion

The following acronyms are used, with definitions, in the Standard Technical Specifications:

ACOT	ANALOG CHANNEL OPERATIONAL TEST
ADS	Automatic Depressurization System
ADV	atmospheric dump valve
AFD	axial flux difference
AFW	auxiliary feedwater
AIRP	air intake, recirculation, and purification
ALARA	as low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
AOT	allowed outage time
APD	axial power distribution
APLHGR	AVERAGE PLANAR LINEAR HEAT GENERATION RATE
APRM	average power range monitor
APSR	axial power shaping rod
ARO	all rods out
ARC	auxiliary relay cabinets
ARS	Air Return System
ARTS	Anticipatory Reactor Trip System
ASGT	asymmetric steam generator transient
ASGTPTF	asymmetric steam generator transient protective trip function
ASI	axial shape index
ASME	American Society of Mechanical Engineers

(continued)

APPENDIX A (continued)

ASTM	American Society for Testing Materials
ATWS	anticipated transient without scram
ATWS-RPT	anticipated transient without scram recirculation pump trip
AVV	atmospheric vent valve
BAST	boric acid storage tank
BAT	boric acid tank
BDPS	Boron Dilution Protection System
BIST	boron injection surge tank
BIT	boron injection tank
BOC	beginning of cycle
BOP	balance of plant
BPWS	banked position withdrawal sequence
BWST	borated water storage tank
BTP	Branch Technical Position
CAD	containment atmosphere dilution
CAOC	constant axial offset control
CAS	Chemical Addition System
CCAS	containment cooling actuation signal
CCGC	containment combustible gas control
CCW	component cooling water
CEA	control element assembly
CEAC	control element assembly calculator
CEDM	control element drive mechanism
CFT	core flood tank
CIAS	containment isolation actuation signal
COLR	CORE OPERATING LIMITS REPORT
COLSS	Core Operating Limits Supervisory System
CPC	core protection calculator
CPR	critical power ratio
CRA	control rod assembly
CRD	control rod drive
CRDA	control rod drop accident
CRDM	control rod drive mechanism
CREHVAC	Control Room Emergency Air Temperature Control System
CREFS	Control Room Emergency Filtration System
CREVS	Control Room Emergency Ventilation System
CRFAS	Control Room Fresh Air System
CS	core spray
CSAS	containment spray actuation signal

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CST	condensate storage tank
CVCS	Chemical and Volume Control System
DBA	Design Basis Accident
DBE	Design Basis Event
DF	decontamination factor
DG	diesel generator
DIV	drywell isolation valve
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOP	dioctyl phthalate
DPIV	drywell purge isolation valve
DRPI	digital rod position indicator
EAB	exclusion area boundary
ECCS	Emergency Core Cooling System
ECW	essential chilled water
ECP	estimated critical position
EDG	emergency diesel generator
EFAS	Emergency Feedwater Actuation System
EFIC	emergency feedwater initiation and control
EFCV	excess flow check valve
EFPDs	effective full power days
EFPYs	effective full power years
EFW	emergency feedwater
EHC	electro-hydraulic control
EOC	end of cycle
EOC-RPT	end of cycle recirculation pump trip
ESF	engineered safety feature
ESFAS	Engineered Safety Feature Actuation System
ESW	essential service water
EVS	Emergency Ventilation System
FBACS	Fuel Building Air Cleanup System
FCV	flow control valve
FHAVS	Fuel Handling Area Ventilation System
FSPVS	Fuel Storage Pool Ventilation System
FRC	fractional relief capacity
FR	Federal Register
FTC	fuel temperature coefficient
FWLB	feedwater line break

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HCS	Hydrogen Control System; Hydrazine Control System
HCU	hydraulic control unit
HIS	Hydrogen Ignition System
HELB	high energy line break
HEPA	high efficiency particulate air
HMS	Hydrogen Mixing System
HPCI	high pressure coolant injection
HPCS	high pressure core spray
HPI	high pressure injection
HPSI	high pressure safety injection
HPSP	high power setpoint
HVAC	heating, ventilation, and air conditioning
HZP	hot zero power
ICS	Iodine Cleanup System
IEEE	Institute of Electrical and Electronic Engineers
IGSCC	intergranular stress corrosion cracking
IRM	intermediate range monitor
ISLH	inservice leak and hydrostatic
ITC	isothermal temperature coefficient
K-relay	control relay
LCS	Leakage Control System
LEFM	linear elastic fracture mechanics
LER	Licensee Event Report
LHGR	LINEAR HEAT GENERATION RATE
LHR	linear heat rate
LLS	low-low set
LOCA	loss-of-coolant accident
LOCV	loss of condenser vacuum
LOMFW	loss of main feedwater
LOP	loss of power
LOPS	loss of power start
LOVS	loss of voltage start
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LPD	local power density
LPI	low pressure injection
LPRM	local power range monitor
LPSI	low pressure safety injection
LPSP	low power setpoint

(continued)

LPZ	low population zone
LSSS	limiting safety system settings
LTA	lead test assembly
LTOP	low temperature overpressure protection
MAPLHGR	maximum average planar linear heat generation rate
MAPFAC	MAPLHGR factor
$MAPFAC_f$	MAPLHGR factor, flow-dependent component
$MAPFAC_p$	MAPLHGR factor, power-dependent component
MCPR	MINIMUM CRITICAL POWER RATIO
MCR	main control room
MCREC	main control room environmental control
MFI	maximum flow interlock
MFIV	main feedwater isolation valve
MFLPD	maximum fraction of limiting power density
MFRV	main feedwater regulation valve
MFW	main feedwater
MG	motor-generator
MOC	middle of cycle
MSIS	main steam isolation signal
MSIV	main steam isolation valve
MSLB	main steam line break
MSSV	main steam safety valve
MTC	moderator temperature coefficient
NDT	nil-ductility temperature
NDTT	nil-ductility transition temperature
NI	nuclear instrument
NIS	Nuclear Instrumentation System
NMS	Neutron Monitoring System
NPSH	net positive suction head
NSSS	Nuclear Steam Supply System
ODCM	Offsite Dose Calculation Manual
OPDRV	operation with a potential for draining the reactor vessel
OTSG	once-through steam generator
PAM	post-accident monitoring
PCCGC	primary containment combustible gas control
PCI	primary containment isolation

(continued)

PCIV	primary containment isolation valve
PCHRS	Primary Containment Hydrogen Recombiner System
PCP	Process Control Program
PCPV	primary containment purge valve
PCT	peak cladding temperature
PDIL	power dependent insertion limit
PDL	power distribution limit
PF	position factor
PIP	position indication probe
PIV	pressure isolation valve
PORV	power-operated relief valve
PPS	Plant Protective System
PRA	probabilistic risk assessment
PREACS	Pump Room Exhaust Air Cleanup System; Penetration Room Exhaust Air Cleanup System
PSW	plant service water
P/T	pressure and temperature
PTE	PHYSICS TEST exception
PTLR	PRESSURE AND TEMPERATURE LIMITS REPORT
QA	quality assurance
QPT	quadrant power tilt
QPTR	quadrant power tilt ratio
QS	quench spray
RACS	Rod Action Control System
RAOC	relaxed axial offset control
RAS	recirculation actuation signal
RB	reactor building
RBM	rod block monitor
RCCA	rod cluster control assembly
RCIC	reactor core isolation cooling
RCIS	Rod Control and Information System
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	Reactor Coolant System
REA	rod ejection accident
RHR	residual heat removal
RHRSW	residual heat removal service water
RMCS	Reactor Manual Control System
RPB	reactor pressure boundaries
RPC	rod pattern controller
RPCB	reactor power cutback

(continued)

RPIS	Rod Position Information System
RPS	Reactor Protection System
RPT	recirculation pump trip
RPV	reactor pressure vessel
RS	recirculation spray
RT	reference temperature
RT_{NDT}	nil-ductility reference temperature
RTCB	reactor trip circuit breaker
RTD	resistance temperature detector
RTM	reactor trip module
RTP	RATED THERMAL POWER
RTS	Reactor Trip System
RWCU	reactor water cleanup
RWE	rod withdrawal error
RWL	rod withdrawal limiter
RWM	rod worth minimizer
RWP	Radiation Work Permit
RWST	refueling water storage tank
RWT	refueling water tank
SAFDL	specified acceptable fuel design limits
SBCS	Steam Bypass Control System
SBO	station blackout
SBVS	Shield Building Ventilation System
SCAT	spray chemical addition tank
SCI	secondary containment isolation
SCR	silicon controlled rectifier
SDV	scram discharge volume
SDM	SHUTDOWN MARGIN
SER	Safety Evaluation Report
SFRCS	Steam and Feedwater Rupture Control System
SG	steam generator
SGTR	steam generator tube rupture
SGTS	Standby Gas Treatment System
SI	safety injection
SIAS	safety injection actuation signal
SIS	safety injection signal
SIT	safety injection tank
SJAE	steam jet air ejector
SL	Safety Limit
SLB	steam line break
SLC	standby liquid control
SLCS	Standby Liquid Control System
SPMS	Suppression Pool Makeup System
SRM	source range monitor

(continued)

S/RV	safety/relief valve
S/RVDL	safety/relief valve discharge line
SSPS	Solid State Protection System
SSW	standby service water
SWS	Service Water System
STE	special test exception
STS	Standard Technical Specifications
TADOT	trip actuating device operational test
TCV	turbine control valve
TIP	transversing incore probe
TLD	thermoluminescent dosimeter
TM/LP	thermal margin/low pressure
TS	Technical Specifications
TSV	turbine stop valve
UHS	Ultimate Heat Sink
VCT	volume control tank
VFTP	Ventilation Filter Testing Program
VHPT	variable high power trip
v/o	volume percent
VS	vendor specific
ZPMB	zero power mode bypass

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This draft report documents the results of the NRC staff review of new Standard Technical Specifications (STS) proposed by the BWR Owners Group for the BWR/4 design. The new STS were developed based on the criteria in the interim Commission Policy Statement on Technical Specification Improvements for Nuclear Power Reactors, dated February 6, 1987. The new STS will be used as bases for individual nuclear power plant owners to develop improved plant-specific technical specifications. The NRC staff is issuing this draft new STS for a 30 working-day comment period. Following the comment period, the NRC staff will analyze comments received, finalize the new STS, and issue them for plant-specific implementation. This report contains three volumes. Volume 1 contains the Specifications for all sections of the new STS. Volume 2 contains the Bases for Sections 2.0 - 3.3 of the new STS and Volume 3 contains the Bases for Sections 3.4 - 3.10 of the new STS.

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