NUREG-1430
Vol. 3

Standard Technical Specifications
Babcock and Wilcox Plants

Bases (Sections 3.4–3.9)

Draft Report for Comment

Issued by the
U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1991

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STANDARD TECHNICAL SPECIFICATIONS
BABCOCK AND WILCOX PLANTS

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PREFACE

This DRAFT NUREG presents the results of the Nuclear Regulatory Commission (NRC) staff review of the Babcock and Wilcox Owners Group (B&WOG) proposed new Standard Technical Specifications (STS). 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 PWRs designed by Babcock and Wilcox (B&W). 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-1430, "Standard Technical Specifications, Babcock and Wilcox Plants." 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 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady-state envelope. The limits placed on DNB-related parameters assure that these parameters will not be less conservative than were assumed in the analyses and thereby provide assurance that the minimum departure from nucleate boiling ratio (DNBR) will meet the required criteria for each of the transients analyzed.

The LCO for minimum RCS pressure is consistent with operation within the nominal operating envelope and is above that used as the initial pressure in the analyses. A pressure greater than the minimum specified will produce a higher minimum DNBR. A pressure lower than the minimum specified will cause the plant to approach the DNB limit.

The LCO for maximum RCS coolant hot leg temperature is consistent with full power operation within the nominal operating envelope and is lower than the initial hot leg temperature in the analyses. A hot leg temperature lower than that specified will produce a higher minimum DNBR. A temperature higher than that specified will cause the plant to approach the DNB limit.

The RCS flow rate is not expected to vary during operation with all pumps running. The LCO for the minimum RCS flow rate corresponds to that assumed for the DNB analyses. A higher RCS flow rate will produce a higher DNBR. A lower RCS flow will cause the plant to approach the DNB limit.

APPLICABLE SAFETY ANALYSES

The requirements of LCO 3.4.1 represent the initial conditions for DNB limited transients analyzed in the plant safety analysis (Ref. 1). The safety analysis has shown that transients initiated from the limits of this LCO will

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

meet the DNBR criterion of ≥ [1.3]. This is the acceptance limit for the RCS DNB parameters. Changes to the facility which could impact these parameters must be assessed for their impact on the DNBR criterion. The transients analyzed for include loss of coolant flow events and dropped or stuck control rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE OPERATING LIMITS," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)."

The core outlet pressure assumed in the safety analyses is 2135 psia. The minimum pressure specified in LCO 3.4.1 is the limit value in the reactor coolant loop as measured at the hot leg pressure tap.

The safety analyses are performed with an assumed RCS coolant average temperature of 581°F (579°F plus 2°F allowance for calculational uncertainty). The corresponding hot leg temperature of 604.6°F is calculated by assuming an RCS core outlet pressure of 2135 psia and an RCS flow rate of 374,880 gpm. The maximum temperature specified is the limit value at the hot leg resistance temperature detector.

The safety analyses are performed with an assumed RCS flow rate of 374,880 gpm. The minimum flow rate specified in LCO 3.4.1 is the minimum mass flow rate.

Analyses have been performed to establish the pressure, temperature, and flow requirements for three-pump and four-pump operation. The flow limits for three-pump operation are substantially lower than for four-pump operation. To meet the DNB criterion, a corresponding maximum power limit is required (see Bases for LCO 3.4.4, "RCS Loops—MODES 1 and 2").

The RCS DNB parameter limits satisfy Criterion 2 of the NRC Interim Policy Statement because they limit the variations of RCS pressure, temperature, and flow, which are initial conditions in the safety analyses.

LCO

This LCO provides limits on the monitored process variables, RCS loop (hot leg) pressure, RCS hot leg temperature, and

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(continued)

BASES (continued)

LCO (continued)

RCS total flow rate to ensure that the core operates within the limits assumed for the plant safety analyses. Operating within these limits will result in meeting DNBR criteria in the event of a DNB limited transient.

The pressure and temperature limits are to be applied to the loop with two reactor coolant pumps running for the three reactor coolant pumps operating condition.

The LCO numerical values for pressure, temperature, and flow are given for the measurement location but have not been adjusted for instrument error. Plant-specific limits of instrument error are established by the plant staff to meet the operational requirements of this LCO.

APPLICABILITY

In MODE 1, the limits on RCS pressure, RCS hot leg temperature, and RCS flow rate must be maintained during steady state with four pump or three pump operation in order to assure that DNBR criteria will be met in the event of an unplanned loss of coolant flow or other DNBR limiting transient. In all other MODES the power level is low enough so that DNBR is not a concern.

The limit on RCS pressure may be exceeded during short-term operational transients such as a THERMAL POWER ramp increase in excess of 5% of RATED THERMAL POWER (RTP) per minute or a THERMAL POWER step increase of greater than 10% of RTP. These conditions represent short-term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels less than 100% of RTP, increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB-related parameters is provided in Safety Limit (SL) 2.1.1, "Reactor Core Safety Limits." Those limits are less restrictive than the limits of LCO 3.4.1, but violation of an SL merits a stricter, more severe Required Action. Should a violation of LCO 3.4.1 occur, the operator must check whether an SL may have been exceeded.

(continued)

BASES (continued)

ACTIONS

A.1

Loop pressure and hot leg coolant temperature are controllable and measurable parameters. With one or both of these parameters not within the LCO limits, action must be taken to restore the parameters.

RCS flow rate is not a controllable parameter and is not expected to vary during steady-state four-pump or three-pump operation. If the flow rate is below the LCO limit, then power must be reduced as required in Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2-hour Completion Time for restoration of the parameter provides sufficient time to adjust plant parameters, determine the cause for the off-normal condition, and restore the readings within limits. The Completion Time is based on plant operating experience.

The Completion Time of Required Action A.1 has been provided with a Note to clarify that all RCS DNB parameters for this LCO are treated as an entity with a single Completion Time, i.e., the Completion Time is on a Condition basis.

RCS loop pressure, hot leg temperature, and flow rate are considered out of limits if the equipment used to measure those parameters is determined to be inoperable. Required Action A.1 applies to restoring such equipment to OPERABLE status.

B.1

If the Required Action is not met within the 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds.

The 6 hours is a reasonable time that permits the plant power to be reduced at an orderly rate in conjunction with even control of steam generator heat removal.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12-hour Surveillance of loop (hot leg) pressure is sufficient to ensure that the pressure can be restored to a normal operation, steady-state condition following load changes and other expected transient operations. The RCS pressure value specified is dependent on the number of pumps in operation and has been adjusted to account for the pressure loss difference between the core exit and the plant safety analysis is 2135 psia. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation is within safety analysis assumptions.

[For this facility, RCS loop pressure is measured as follows:]

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12-hour Surveillance of hot leg temperature is sufficient to ensure that the RCS coolant temperature can be restored to a normal operation, steady-state condition following load changes and other expected transient operations. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify that operation is within safety analysis assumptions.

[For this facility, RCS hot leg temperature is measured as follows:]

SR 3.4.1.3

The 12-hour Surveillance of RCS total flow rate is performed using the installed flow instrumentation. SR 3.0.4 is not applicable because the pressure, temperature, and flow limits of the LCO are dependent on the number of pumps in operation, and the operating condition must be entered to determine actual values for comparison to the LCO. When the number of pumps is changed, the Surveillance is required at

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the next 12-hour interval; no change of Surveillance Frequency is required because DNB parameters are not expected to be abnormal after the number of pumps is altered, and an event that might exceed DNB is not likely to occur in the short interval.

[For this facility, RCS total flow rate is measured as follows:]

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 18 months allows the installed RCS flow instrumentation to be calibrated and verifies that the actual RCS flow is ≥ the minimum required RCS flow.

The intent of the Surveillance Frequency of 18 months is to reflect the importance of re-verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

The surveillance is modified by a Note that states SR 3.0.4 is not applicable. The Note is necessary to allow measurement of the flow rate at normal operating conditions at power in MODE 1. The surveillance cannot be performed in MODE 2 or below.

REFERENCES

1. [Unit Name] FSAR, Section [15], "[Accident Analysis]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

Establishing the value for the minimum temperature for reactor criticality is based upon considerations for:

a. Operation within the existing instrumentation ranges and accuracies;

b. Operation within the bounds of the existing accident analyses; and

c. Operation with reactor vessel above its minimum nil-ductility reference temperature when the reactor is critical.

The reactor coolant moderator temperature coefficient used in core operating and accident analysis is typically defined for the normal operating temperature range (532°F to 579°F). The Reactor Protection System receives inputs from the narrow-range hot leg temperature detectors which have a range of (520°F to 620°F). The integrated control system controls average temperature (T_{avg}) using inputs of the same range. Nominal T_{avg} for making the reactor critical is 532°F. Safety and operating analyses for lower temperatures have not been made.

APPLICABLE SAFETY ANALYSES

The low power safety analyses assume initial temperatures near the 525°F limit (Ref. 1). These analyses for Design Basis Accidents (DBAs) establish the acceptance limits for the minimum temperature for criticality. Reference to the analyses for these DBAs is used to assess changes to the facility which could affect the minimum temperature for criticality as they relate to the acceptance limits.

This specification preserves limits used in the safety analysis and therefore satisfies Criterion 2 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

The purpose of the LCO is to prevent criticality outside the normal operating regime (532°F - 579°F) and to prevent operation in an unanalyzed condition.

The LCO limit of 525°F has been selected to be within the instrument indicating range (520°F to 620°F). The limit is also set slightly below the lowest power range operating temperature (532°F).

APPLICABILITY

The reactor has been designed and analyzed to be critical in MODES 1 and 2 only and in accordance with this specification. Criticality is not permitted in any other MODE. Therefore this LCO is applicable in MODE 1 and MODE 2 when $K_{eff} \geq 1.0$. Coupled with the applicability definition for criticality is a temperature limit. Monitoring is required at and below a T_{avg} of 530°F. This temperature limit (530°F) has been selected because it is slightly below normal operating temperature.

[Each plant shall specify if exceptions are taken to this LCO for performance of PHYSICS TESTS or other special tests.]

ACTIONS

A.1

With T_{avg} below 525°F, restoration is required within 15 minutes. The Completion Time of 15 minutes restricts the period for operation outside the analyzed limits. The Completion Time is sufficient for the operator to accomplish the specified actions.

The RCS minimum temperature for criticality is considered out of limits if the equipment used to measure T_{avg} 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)

A.2

If the Required Action is not met within the required 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 MODE 3 in 30 minutes. Rapid reactor shutdown can be readily and practically achieved in a 30-minute period, and thus the basis for the time is derived from the ability to perform the action and the urgency of maintaining the plant within the analyzed range.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

T_{avg} is required to be verified above 525°F within 15 minutes prior to achieving criticality and every 30 minutes thereafter. The 15-minute time period is long enough to allow the operator to adjust temperatures or delay criticality so the LCO will not be violated. The 30-minute time is frequent enough to prevent inadvertent violation of the LCO.

While Surveillance is required whenever the reactor is critical and temperature is at or below 530°F, in practice the Surveillance is most appropriate during the period when the reactor is brought critical.

[For this facility, T_{avg} is measured as follows:]

REFERENCES

1. [Unit Name] FSAR, Section [15], "[Title]."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 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 pressure and temperature 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 3.4.3 contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides both heatup and criticality limits.

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 pressure and temperature 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, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

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

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BASES (continued)

BACKGROUND (continued)

cause stress concentrations at flaw locations, which, in 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), 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

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BASES (continued)

BACKGROUND (continued)

established by experimental means. The neutron 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 American Society for Testing Materials (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.

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BASES (continued)

BACKGROUND (continued)

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 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 P/T span of the 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 to generate the 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 limit includes the Reference 1 requirement that it be no less than 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for the ISLH testing. However, the criticality limit is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature For Criticality."

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

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BASES (continued)

BACKGROUND (continued)

to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7) provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident analyses. They are prescribed during normal operation to 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, an unanalyzed condition. 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.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

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 calculated and compared to a reference 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. Adjust the curves. 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, $\frac{1}{4}$ T, and a length of $\frac{3}{2}$ 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

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

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 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 two elements of this LCO are:

a. The limit curves for heatup, cooldown, ISLH testing, and criticality; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to non-ductile failure.

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BASES (continued)

LCO (continued)

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ILHT 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.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB 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 specification 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, 4, and 5) or ISLH testing, their applicability is at all times in keeping with the concern for non-ductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, RCS Minimum Temperature for Criticality"; and Safety Limit (SL) 2.1, "Safety Limits," also provide operational restrictions for P/T and maximum pressure. MODES 1 and 2 are above the temperature range of

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BASES (continued)

APPLICABILITY (continued)

concern for non-ductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

The actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from 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 returned to 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 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. The evaluation for a mild violation is possible within this time, but more severe violations may require

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BASES (continued)

ACTIONS (continued)

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 Actions A.1 and 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. In reduced conditions, the possibility of propagation of undetected flaws is decreased.

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

If the required 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 Actions B.1 and 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.

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BASES (continued)

ACTIONS (continued)

P/T are reduced by placing the plant in MODE 3 within 6 hours and in MODE 5 with RCS pressure < 500 psig within 36 hours.

The 6-hour 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.

The 36-hour Completion Time for achieving MODE 5 also considers operating experience to reach the required MODE from full power in an orderly manner and without challenging plant systems. The time 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. The pressure limit of 500 psig corresponds to the LCO 3.4.12 low temperature overpressure protection limit.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within LCO limits is required every 30 minutes when RCS P/T 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 assessment and correction for minor deviations within a reasonable time.

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. No SR is given for criticality operations because LCO 3.4.2, "RCS Minimum Temperature for Criticality," contains a more restrictive requirement.

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

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BASES (continued)

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.

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. BAW-10046A, Rev. 1, "Methods of Compliance with Fracture Toughness and Operational Requirements of 10 CFR 50, Appendix G," July 1977.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops—MODES 1 & 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission-product release to the environment; and

e. Removal of the heat generated in the fuel due to fission-product decay following a unit shutdown.

The RCS configuration for heat transport uses two RCS loops. Each RCS loop contains an SG and two reactor coolant pumps (RCPs). An RCP pump is located in each of the two SG cold legs. The pump flow rate has been sized to provide core heat removal with appropriate margin to departure from nucleate boiling (DNB) during power operation and for anticipated transients originating from power operation. This specification requires two RCS loops with either three or four pumps to be in operation. With three pumps in operation the reactor power level is restricted to [79.9]% of RATED THERMAL POWER (RTP) to preserve the core power-to-flow relationship, thus maintaining the margin to DNB. The intent of the specification is to require core heat removal with forced flow during power operation. Specifying the minimum number of pumps is an effective technique for designating the proper forced flow rate for heat transport, and specifying two loops provides for the needed amount of heat removal capability for the allowed

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BASES (continued)

BACKGROUND (continued)

power levels. Specifying two RCS loops also provides the provides the minimum necessary paths (two SGs) for heat removal.

The Reactor Protection System (RPS) nuclear overpower trip setpoint is automatically reduced when one pump is taken out of service; manual resetting is not necessary.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the Design Bases Accident (DBA) initial conditions including: RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate which is represented by the number of pumps in service.

Both transient and steady-state analyses have been performed to establish the effect of flow on DNB. The transient or accident analysis for the plant has been performed assuming either three or four pumps are in operation. The majority of the plant safety analysis is based on initial conditions at high core power or zero power. The accident analyses which are of most importance to RCP operation are the four pump coastdown, single pump locked rotor, single pump [broken shaft or coastdown], and rod withdrawal events (Ref 1).

The above analyses are for DBAs that establish the acceptance limits for the RCS loops. Reference to the [illegible] for these DBAs is used to assess changes to the RCS lo[illegible] they relate to the acceptance limits.

Steady-state DNB analysis has been performed for four, three, and two pump combinations. For four pump operation, the steady-state DNB analysis, which generates the pressure temperature Safety Limit, (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of [112]% RATED THERMAL POWER (RTP). This is the design overpower condition for four pump operation. The [112]% value is the accident analysis setpoint of the nuclear overpower (high flux) trip and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points which result in a minimum DNBR ≥ the critical heat flux correlation limit.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The three pump pressure temperature limit is tied to the steady-state DNB analysis which is evaluated each cycle. The flow used is the minimum allowed for three pump operation. The actual RCS flow rate will exceed the assumed flow rate. With three pumps operating, overpower protection is automatically provided by the power to flow ratio of the RPS nuclear overpower based on RCS flow and AXIAL POWER IMBALANCE setpoint. The maximum power level for three pump operation is [79.9]% of RTP and is based on the three pump flow as a fraction of the four pump flow at full power.

Although the specification limits operation to a minimum of three pumps total, existing design analyses show that operation with one pump in each loop (two pumps total) is acceptable when core thermal power is restricted to be proportionate to the flow. However, continued power operation with two reactor coolant pumps removed from service is not allowed by this specification.

The number of loops and the RCS flow as represented by the number of pumps in operation satisfies Criterion 2 of the NRC Interim Policy Statement, because the flow is an initial condition for transient and steady-state analyses.

LCO

The purpose of this LCO is to require adequate forced flow for core heat removal. Flow is represented by the number of reactor coolant pumps in operation in both RCS loops for removal of heat by the two steam generators. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power; if only three pumps are available, power must be reduced.

Each OPERABLE loop consists of two RCPs providing forced flow for heat transport to an SG which is OPERABLE in accordance with the Steam Generator Tube Surveillance Program. RCS loop OPERABILITY also includes the appropriate instrumentation for flow, level, pressure, and temperature for control, protection, and indication. [These specific instrumentation channels are:]

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

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BASES (continued)

LCO (continued)	[For this facility, those required support systems which, upon their failure, do not require declaring the RCS loops inoperable and their justification are as follows:]
APPLICABILITY	In MODES 1 and 2 the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage. Maximum decay heat production is approximately [7]% of RTP. As such, the forced circulation flow and heat sink requirements are reduced for lower, non-critical MODES as indicated by the LCOs for MODES 3, 4, and 5. Operation in other MODES is covered by LCO 3.4.5 (MODE 3), LCO 3.4.6 (MODE 4), LCO 3.4.7 (MODE 5, Loops Filled), and LCO 3.4.8 (MODE 5, Loops Not Filled).
ACTIONS	A.1 If one or more RCS loops or pumps is not OPERABLE or in operation, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging safety systems.
SURVEILLANCE REQUIREMENTS	SR 3.4.4.1 This Surveillance requires verification of the required number of loops and pumps in operation and reactor coolant circulation every 12 hours. Verification includes flow rate and temperature monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The 12-hour interval has been shown by operating

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.4.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity. Even though this surveillance can not be performed at normal operating conditions, its inclusion in this specification is necessary to invoke the Technical Specification requirement for this important inspection program. The preservice, inservice and, if required, augmented inservice inspections performed at shutdown are to demonstrate SG performance and gauge its reliability.

REFERENCES

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops—MODE 3

BASES

BACKGROUND

The primary function of the reactor coolant in MODE 3 is removal of decay heat and transfer of this heat, via the steam generators (SGs), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 3 reactor coolant pumps (RCPs) are used to provide forced circulation heat removal during heatup and cooldown. The number of RCPs in operation will vary to meet operational needs, and the intent of this LCO is to provide forced flow from at least one RCP for core heat removal and transport. The flow provided by one RCP is adequate for heat removal and for boron mixing. However, two RCS loops are required to be OPERABLE to satisfy the single failure criterion.

Reactor coolant natural circulation is not normally used, however the natural circulation flow rate is sufficient for core cooling. If entry into natural circulation is required, the reactor coolant at the highest elevation of the hot leg must be maintained subcooled for single phase circulation. Boron reduction in natural circulation is prohibited because mixing to obtain a homogeneous concentration in all portions of the RCS cannot be assured.

APPLICABLE SAFETY ANALYSES

No safety analyses are performed with initial conditions in MODE 3. Analyses have shown that the rod withdrawal event initiated from MODE 3 with one RCS loop in operation is bounded by the rod withdrawal initiated from MODE 2. The analysis of the rod withdrawal event establishes the acceptance limits for the RCS loops in MODE 3. Reference to the analysis for this event is used to assess changes to the RCS loops as they relate to the acceptance limits.

Failure to provide heat removal may result in challenges to a fission-product barrier. The RC loops are part of the primary success path which functions or actuates to prevent

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission-product barrier. As such this LCO satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	The purpose of this LCO is to require two loops to be available for heat removal thus providing redundancy. The LCO requires the two loops to be OPERABLE with the intent of requiring both SGs to be capable of transferring heat from the reactor coolant at a controlled rate. Forced reactor coolant flow is the required way to transport heat, although natural circulation flow provides adequate removal. A minimum of one running RCP meets the LCO requirement for one loop in operation. The LCO Note permits a limited period of operation without RCPs. All RCPs may be de-energized for ≤ 8 hours per 24-hour period for the cooldown transition to the Decay Heat Removal (DHR) System, and otherwise may be de-energized for ≤ 1 hour per 8-hour period. This means that natural circulation has been established. When in natural circulation, boron reduction is prohibited because an even concentration distribution throughout the RCS cannot be assured. Core outlet temperature is to be maintained at least 10°F below the saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. In MODES 3, 4, and 5 it is sometimes necessary to stop all RCP or DHR pump forced circulation (e.g., change operation from one DHR train to the other, perform surveillance or startup testing, perform the transition to and from DHR System cooling, or to avoid operation below the RCP minimum net positive suction head limit). The time period is acceptable because natural circulation is adequate for heat removal, or the reactor coolant temperature can be maintained subcooled and boron stratification affecting reactivity control is not expected.

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BASES (continued)

LCO (continued)

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG which is OPERABLE in accordance with the Steam Generator Tube Surveillance Program. RCS loop OPERABILITY also includes the appropriate flow, level, pressure, and temperature instrumentation for control, protection, and indication. [These specific instrumentation channels are:]

An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

[For this facility, the following support systems are required to be OPERABLE to ensure RCS loop OPERABILITY in MODE 3:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RCS loops inoperable in MODE 3 and their justification are as follows:]

APPLICABILITY

In MODE 3, the heat load is lower than at power, therefore one RCS loop in operation is adequate for transport and heat removal. A second RCS loop is required OPERABLE but not in operation for redundant heat removal capability.

Operation in other MODES is covered by LCO 3.4.4 (MODES 1 and 2), LCO 3.4.6 (MODE 4), LCO 3.4.7 (MODE 5, Loops Filled), and LCO 3.4.8 (MODE 5, Loops Not Filled).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for forced flow heat removal has been lost.

The Required Action is restoration of the RCS loop to OPERABLE status within a Completion Time of 72 hours. This time allowance is a justified period to be without the redundant non-operating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core.

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BASES (continued)

ACTIONS (continued)

B.1

If restoration is not possible within 72 hours, the unit must be placed in MODE 4. In MODE 4, the plant may be placed on the DHR System. The allowed Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions without challenging plant systems.

C.1 and C.2

If no RCS loop is OPERABLE or in operation, except as provided in Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be immediately suspended. This is necessary because boron dilution requires forced circulation for proper homogenization. Action to restore one RCS loop to operation shall be immediately initiated and continued until one RCS loop is restored to operation. The immediate Completion Time reflects the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This Surveillance requires verification of the required number of loops and pumps in operation and reactor coolant circulation every 12 hours. Verification includes flow rate and temperature monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.5.2

Verification that the required number of RCPs are OPERABLE ensures that the single failure criterion is met and that an additional RCS loop can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

proper breaker alignment and power availability to the required RCPs. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops—MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the steam generator(s) (SG(s)) or decay heat removal (DHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 4, either reactor coolant pumps (RCPs) or DHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RCP or one DHR pump for decay heat removal and transport. The flow provided by one RCP or DHR pump is adequate for heat removal. The other intent of this LCO is to require that two paths (loops) be available to provide redundancy for heat removal (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS and DHR loops provide this circulation.

The analysis for the boron dilution event establishes the acceptance limits for the RCS loops in MODE 4. Reference to the analysis for this event is used to assess changes to the RCS loops as they relate to the acceptance limits.

Failure to provide decay heat removal may result in challenges to a fission-product barrier. Although the DHR System does not meet any specific criterion of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reduction, and this LCO is thus retained as a Specification.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that two loops, RCS or DHR, be OPERABLE in MODE 4 and one of these loops be in operation. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. The second loop which is required to be OPERABLE meets the single failure criterion.

The LCO Note permits a limited period of operation without RCPs. All RCPs may be de-energized for ≤ 8 hours per 24-hour period for the cooldown transition to the DHR systems and otherwise may be de-energized for ≤ 1 hour per 8-hour period. This means that natural circulation has been established using the SGs. With the RCS in natural circulation, boron reduction is prohibited because an even concentration distribution throughout the RCS cannot be assured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

The LCO Note also permits the DHR pumps to be stopped for 1 hour per 8-hour period. When the DHR pumps are stopped, no alternate heat removal path exists, unless the RCS and SGs have been placed in service in forced or natural circulation. The response of the RCS without the DHR System depends on the core decay heat load and the length of time that the DHR pumps are stopped. As decay heat diminishes, the effects on RCS temperature and pressure diminish. Without cooling by DHR, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (pressure and temperature (P/T) limits or low temperature overpressure protection (LTOP)) must be observed and forced DHR flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping both DHR trains are to be limited to:

a. Situations where pressure and P/T increases can be maintained well within the allowable pressure (P/T and LTOP) and 10°F subcooling limits; or

b. Situations where an alternate heat removal path through the SG is in operation.

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BASES (continued)

LCO (continued)

The LCO Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be assured.

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program and has the minimum water level specified in LCO [3.7.16]. RCS loop OPERABILITY also includes the appropriate flow, level, pressure, and temperature instrumentation for control, protection, and indication. [These specific instrumentation channels are:]

Similarly for the DHR System, an OPERABLE DHR loop is comprised of the OPERABLE DHR pump(s) providing forced flow to the DHR heat exchanger(s), along with appropriate flow and temperature instrumentation for control, protection, and indication. [These specific instrumentation channels are:] RCPs and DHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

[For this facility, the following support systems are required to be OPERABLE to ensure RCS loop OPERABILITY in MODE 4:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RCS loops inoperable in MODE 4 and their justification are as follows:]

APPLICABILITY

In MODE 4, this LCO applies because it is possible to remove core decay heat and to provide proper boron mixing with either the RCS loops and SGs or the DHR System.

Operation in other MODES is covered by LCO 3.4.4 (MODES 1 and 2), LCO 3.4.5 (MODE 3), LCO 3.4.7 (MODE 5, Loops Filled), and LCO 3.4.8 (MODE 5, Loops Not Filled).

(continued)

BASES (continued)

ACTIONS

A.1

If only one RCS loop is OPERABLE and in operation, redundancy for heat removal is lost. Action must be initiated to restore a second loop to OPERABLE status. The Completion Time of 15 minutes emphasizes the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If only one DHR loop is OPERABLE and in operation, an inoperable RCS or DHR loop must be restored to OPERABLE status to satisfy single failure considerations. The Completion Time of 1 hour is based on the fact that one loop is still available for cooldown for the reduced heat loads of this operating MODE.

If Required Action B.1 cannot be accomplished within the required Completion Time and a DHR loop is OPERABLE, the unit must be placed in MODE 5 within the following 24 hours. Placing the unit in MODE 5 is a conservative action with regard to decay heat removal. With only one DHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining DHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200-300°F). The Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 from full power in an orderly manner and without challenging safety systems.

C.1 and C.2

If no RCS or DHR loops are OPERABLE or in operation, except during conditions permitted by the Note in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or DHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The Action to restore must continue until one loop is restored to operation.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance requires verification of the required number of loops in operation every 12 hours to ensure forced flow is providing heat removal. Verification includes flow rate and temperature monitoring. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.6.2

Verification that the required number of loops are OPERABLE ensures that additional RCS or DHR loops can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls and has been shown to be acceptable by operating experience.

REFERENCES

1. Generic Letter 88-17, "Loss of Decay Heat Removal," U.S. Nuclear Regulatory Commission, October 17, 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops—MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the steam generators (SGs) or decay heat removal (DHR) heat exchangers. While the principle means for decay heat removal is via the DHR System, the SGs are specified as a backup means for redundancy. Although the SGs cannot remove heat unless steaming occurs (which is not possible in MODE 5), they are available as a temporary heat sink and can be used by allowing the RCS to heat up into the temperature region of MODE 4 where steaming can be effective for heat removal. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, DHR loops are the principal means for heat removal. The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one DHR loop for decay heat removal and transport. The flow provided by one DHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal (Ref. 1).

The LCO provides for either SG heat removal or DHR System heat removal. In this MODE, reactor coolant pump (RCP) operation may be restricted because of net positive suction head (NPSH) limitations and the SG will not be able to provide steam for the turbine-driven feed pumps. However, to ensure that the SGs can be used as a heat sink, a motor-driven feedwater pump is needed, because it is independent of steam and the high entry point in the generator can stimulate natural circulation, if required. The SGs are primarily a backup to the DHR pumps, which are used for forced flow. By requiring the SGs to be a backup heat removal path, the option to increase RCS pressure and temperature (P/T) for heat removal in MODE 4 is provided.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The DHR loops provide this circulation.

The analysis for the accidental boron dilution event establishes the acceptance limits for the RCS loops in MODE 5. Reference to the analysis for this event is used to assess changes to the RCS loops as they relate to the acceptance limits.

Failure to provide decay heat removal may challenge the integrity of a fission-product barrier. Although the DHR System does not meet any specific criteria of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reducton, and this LCO is thus retained as a Specification.

LCO

The purpose of this LCO is to require that at least one of the DHR loops be OPERABLE and in operation with an additional DHR loop OPERABLE or both SGs with secondary-side water level ≥ [ ]%. One DHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. The second DHR loop is normally maintained as a backup to the operating DHR loop and satisfies the single failure criterion. However, if the standby DHR loop is not OPERABLE, a sufficient alternate method of satisfying the single failure criterion is both SGs with their secondary-side water levels ≥ [ ]%. Should the operating DHR loop fail, the SGs could be used to remove the decay heat.

The LCO Note 1 permits the DHR pumps to be stopped for up to 1 hour per 8-hour period. The circumstances for stopping both DHR trains are to be limited to:

a. Situations where P/T increases can be maintained well within the allowable pressure (P/T and low temperature overpressure protection) and 10°F subcooling limits; or

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(continued)

BASES (continued)

LCO (continued)

b. Alternate heat paths through the SGs are in operation.

The LCO Note prohibits boron dilution when DHR forced flow is stopped because an even concentration distribution cannot be assured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble would form and possibly cause a natural circulation flow obstruction. In this MODE, the generators are used as a backup for decay heat removal and, to ensure their availability, the RCS loop flow path is to be maintained with subcooled liquid.

In MODE 5, it is sometimes necessary to stop all RCP or DHR pump forced circulation. This is permitted to change operation from one DHR train to the other, perform surveillance or startup testing, perform the transition to and from the DHR System, or to avoid operation below the RCP minimum NPSH limit. The time period is acceptable because natural circulation is acceptable for heat removal, the reactor coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

Note 2 in the LCO allows one DHR loop to be inoperable for a period of 2 hours provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

LCO Note 3 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of DHR loops from operation when at least one RCP is in operation. This Note provides for the transition to MODE 4 where an RCP is permitted to be in operation and replaces the heat removal function provided by the DHR loops.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump and an OPERABLE DHR heat exchanger along with the appropriate flow and temperature instrumentation for control, protection, and indication. [These specific instrumentation channels are:]

(continued)

(continued)

BASES (continued)

LCO (continued)

DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

[For this facility, the following support systems are required to be OPERABLE to ensure RCS loop OPERABILITY in MODE 5:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RCS loops inoperable in MODE 5 and their justification are as follows:]

APPLICABILITY

In MODE 5 with loops filled, forced circulation is provided by this LCO to remove decay heat from the core and to provide proper boron mixing. One loop of DHR provides sufficient circulation for these purposes.

Operation in other MODES is covered by LCO 3.4.4 (MODES 1 and 2), LCO 3.4.5 (MODE 3), LCO 3.4.6 (MODE 4), and LCO 3.4.8 (MODE 5, Loops Not Filled).

ACTIONS

A.1 and A.2

If only one DHR loop is OPERABLE and in operation, and any SG has secondary-side water level ≤ [ ]%, redundancy for heat removal is lost. The Required Action is to initiate action to restore a second loop to OPERABLE status or initiate action to restore the water level in the SGs, and the action must be taken within 15 minutes. Either Required Action A.1 or A.2 will restore redundant decay heat removal paths. The Completion Times of 15 minutes emphasize the importance of maintaining the availability of two paths for heat removal.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

If no loop is OPERABLE or in operation, except as provided in Note 1 in the LCO, all operations involving the reduction of RCS boron concentration must be suspended and action to restore a DHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal. The action to restore must continue until one loop is restored.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This Surveillance requires verification that at least one DHR loop is in operation and circulating reactor coolant every 12 hours. Verification includes flow rate and temperature monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to the departure from nucleate boiling. The 12-hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.7.2

Verifying the SGs are OPERABLE by ensuring their secondary-side water levels are ≥ [ ]% ensures that the single failure criterion is met if the second DHR loop is not OPERABLE. The Note requires the Surveillance when the LCO requirement is being met by use of the SGs. If both DHR loops are OPERABLE, this Surveillance is not needed. The 12-hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that the second DHR loop is OPERABLE ensures that the single failure criterion is met. The requirement also ensures that the additional loop can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. Generic Letter 88-17, "Loss of Decay Heat Removal," U.S. Nuclear Regulatory Commission, October 17, 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops—MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with loops not filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the decay heat removal (DHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. [Each facility shall define what is meant by "loops not filled" for each SG design. Also expand this definition and background section to cover the mid-loop operation concerns expressed in GL 88-17, "Loss of Decay Heat Removal," 10 CFR 50.54(f) (Ref.1).] The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only DHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one DHR pump for decay heat removal and transport. The other intent of this LCO is to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The DHR loops provide this circulation. The flow provided by one DHR pump is adequate for heat removal and for boron mixing.

The analysis for the accidental boron dilution event establishes the acceptance limits for the RCS loops in MODE 5. Reference to the analysis for this event is used to assess changes to the RCS loops as they relate to the acceptance limits.

Failure to provide decay heat removal may result in challenges to a fission-product barrier. Although the DHR System does not meet any specific criterion of the NRC Interim Policy Statement, it was identified in the Policy Statement as an important contributor to risk reduction, and this LCO is thus retained as a Specification.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that a minimum of two DHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the DHR System unless forced flow is used. A minimum of one running decay heat removal pump meets the LCO requirement for one loop in operation. An additional DHR loop is required to be OPERABLE to meet the single failure criterion.

The LCO Note 1 permits the DHR pumps to be de-energized for ≤ 15 minutes when switching from one train to the other. The circumstances for stopping both DHR pumps are to be limited to situations when the outage time is short and temperature is maintained less than [160]°F. The LCO Note prohibits boron dilution or draining operations when DHR forced flow is stopped.

The LCO Note 2 in the LCO allows one DHR loop to be inoperable for a period of 2 hours provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump providing forced flow to an OPERABLE DHR heat exchanger, along with appropriate flow and temperature instrumentation for control, protection, and indication. [These specific instrumentation channels are:]

DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

[For this facility, the following support systems are required to be OPERABLE to ensure RCS loop OPERABILITY in MODE 5:]

[For this facility, those required support systems which, upon their failure, do not require declaring the RCS loops inoperable in MODE 5 and their justification are as follows:]

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BASES (continued)

APPLICABILITY

In MODE 5, with loops not filled, this LCO requires core heat removal and coolant circulation by the DHR System.

Operation in other MODES is covered by LCO 3.4.4 (MODES 1 and 2), LCO 3.4.5 (MODE 3), LCO 3.4.6 (MODE 4), and LCO 3.4.7 (MODE 5, Loops Filled).

ACTIONS

A.1

If only one required DHR loop is OPERABLE and in operation, redundancy for heat removal is lost. The Action is to initiate activities to restore a second loop to OPERABLE status and must be taken within 15 minutes. The Completion Time emphasizes the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If both required loops are inoperable or the required loop is not in operation except as provided by Note 1 in the LCO, the Action requires immediate suspension of any operation for boron reduction and requires action to immediately start restoration of one OPERABLE loop. The Action for restoration does not apply to the condition of both loops not in operation when the exception NOTE in the LCO is in force. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal. The action to restore must continue until one loop is restored.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance requires verification that at least one loop is in operation and circulating reactor coolant every 12 hours. Verification includes flow rate and temperature monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to departure from nucleate boiling. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.2

Verification that the required number of loops are OPERABLE ensures that the single failure criterion is met. The requirement also ensures that additional loops can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. Generic Letter 88-17, "Loss of Decay Heat Removal," U.S. Nuclear Regulatory Commission, October 17, 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady-state operation and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water volume, the heaters, and the heater control and power supplies. Pressurizer safety valves and pressurizer power-operated relief valves (PORVs) are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power-Operated Relief Valves (PORVs)," respectively.

The maximum water level limit has been established to ensure that a liquid-to-vapor interface exists to permit RCS pressure control during normal operation and proper pressure response for anticipated design basis transients. The water level limit thus serves two purposes:

a. Pressure control during normal operation maintains subcooled reactor coolant in the loops and thus is in the preferred state for heat transport; and

b. By restricting the level to a maximum, expected transient reactor coolant volume increases (pressurizer insurge) will not cause excessive level changes which could result in degraded ability for pressure control.

The maximum level limit permits pressure control equipment to function as designed. The limit preserves the steam space during normal operation, thus both sprays and heaters can operate to maintain the design operating pressure. The level limit also prevents filling the pressurizer (water solid) for anticipated design basis transients, thus assuring that pressure relief devices (PORVs or code

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BASES (continued)

BACKGROUND (continued)

safety valves) can control pressure by steam relief rather than water relief. If the level limits were exceeded prior to a transient that creates a large pressurizer insurge volume leading to water relief, the maximum RCS pressure might exceed the design safety limit of 2750 psig or damage may occur to the PORVs or pressurizer code safety valves.

The pressurizer heaters are used to maintain a pressure in the RCS so reactor coolant in the loops is subcooled and thus in the preferred state for heat transport to the steam generators. This function must be maintained with a loss of offsite power. Consequently, the emphasis of this LCO is to ensure that the essential power supplies and the associated heaters are adequate to maintain pressure for RCS loop subcooling with an extended loss of offsite power.

A minimum required available capacity of 126 kW assures that the RCS pressure can be maintained. Unless adequate heater capacity is available, reactor coolant subcooling cannot be maintained indefinitely. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1 and 2, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. No safety analyses are performed in lower MODES. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of non-condensible gases normally present. The steam bubble limits the volume of non-condensible gases.

Safety analyses presented in the FSAR do not take credit for pressurizer heater operation, however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The maximum level limit is of prime interest for the loss of main feedwater (LOMFW) event. Conservative safety analyses assumptions for this event indicate that it produces the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

largest increase of pressurizer level caused by a moderate frequency event. Thus this event has been selected to establish the pressurizer water level limit. Assuming proper response action by emergency systems, the level limit prevents water relief through the pressurizer safety valves. Since prevention of water relief is a goal for abnormal transient operation, rather than a Safety Limit, the value for pressurizer level is nominal and is not adjusted for instrument error.

Evaluations performed for the design basis large-break loss-of-coolant accident (LOCA), which assumed a higher maximum level than assumed for the LOMFW event, have been made. The higher pressurizer level assumed for the LOCA is the bases for the volume of reactor coolant released to the containment. The containment analysis performed using the mass and energy release demonstrated that the maximum resulting containment pressure was within design limits.

The above analyses are design basis analyses that are used to establish acceptance limits for the pressurizer. These design basis analyses are referenced to assess changes to the pressurizer to evaluate their effect on the acceptance limits.

The requirement for emergency power supplies is based on NUREG 0737 (Ref. 1). The intent is to allow maintaining the reactor coolant in a subcooled condition with natural circulation at hot, high pressure conditions for an undefined, but extended, time period after a loss of offsite power. While loss of offsite power is an initial condition or coincident event assumed in many accident analyses, maintaining hot, high pressure conditions over an extended time period is not evaluated as part of FSAR accident analyses.

The maximum pressurizer water level limit satisfies Criterion 2 of the NRC Interim Policy Statement because it prevents exceeding the initial reactor coolant mass which is an input assumption of the LOCA analysis. The maximum water level also permits the pressurizer code safety valves to relieve steam for anticipated pressure increase transients, preserving their function for mitigation. Thus Criterion 3 is also indirectly applicable.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG 0737 (Ref. 1), is the reason for providing an LCO.
LCO	The LCO requirement for the pressurizer to be OPERABLE with a water level ≤ [ ] inches ensures that a steam bubble exists. Limiting the maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady-state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions. The LCO requires a minimum of 126 kW of pressurizer heater OPERABLE and capable of being powered by emergency supplies. As such the LCO addresses both the heaters and the power supplies. The minimum heater capacity required is sufficient to maintain the system near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The exact design value of 126 kW is derived from the use of nine heaters rated at 14 kW each. The amount needed to maintain pressure is dependent on the insulation losses, which can vary due to tightness of fit and condition. The required heaters and their controls must be connected to the emergency buses in a manner that will provide redundant power supply capability. [For this facility, an OPERABLE pressurizer consists of the following:] For this facility, the following support systems are required to be OPERABLE to ensure pressurizer OPERABILITY:] [For this facility, those required support systems which, upon their failure, do not require declaring the pressurizer inoperable and their justification are as follows:]

(continued)

BASES (continued)

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3 and, for pressurizer water level, for MODE 4 with RCS temperature equal to or greater than 275°F. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup. The temperature of 275°F has been designated as the cutoff for applicability because LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," provides a requirement for pressurizer level below 275°F. The LCO does not apply to MODE 5 (loops filled) because LCO 3.4.12 applies. The LCO does not apply to MODE 5 and 6 with partial loop operation.

In MODES 1, 2, and 3, the need to maintain the availability of pressurizer heaters and their emergency power supplies is most pertinent. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODES 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Decay Heat Removal System is in service, and therefore the LCO is not applicable.

ACTIONS

A.1 and A.2

With water level above the limit, action must be taken to restore pressurizer operation to within the bounds assumed in the analyses. This is done by placing the unit in MODE 3 with the control rod drive trip breakers open within 6 hours and placing the unit in MODE 4 with RCS temperature ≤ [275]°F within an additional 6 hours. This takes the unit out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses.

Six hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Further

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BASES (continued)

ACTIONS (continued)

pressure and temperature reduction to MODE 4 with RCS temperature ≤ 275°F places the plant into a MODE where the LCO is not applicable. The 12-hour time to reach the non-applicable MODE is reasonable based on operating experience.

Pressurizer water level is considered out of limits if the equipment used to verify level is determined to be inoperable, and Required Action A.1 applies.

B.1

If the emergency power supplies to the heaters are not capable of providing 126 kW, or the pressurizer heaters are not available, restoration is required in 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power will not occur in this period. Pressure control may be maintained during this time using normal station-powered heaters.

C.1 and C.2

The plant must be placed in a MODE in which the LCO does not apply if pressurizer heater capability cannot be restored within the allowed Completion Time of Required Action B.1. The plant is placed in MODE 3 within 6 hours and in MODE 4 within the following 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging safety systems. Similarly, the Completion Time of 12 hours to reach MODE 4 is reasonable, based on operating experience, to achieve power reduction from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This Surveillance ensures that during steady-state operation, pressurizer water level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing indicated level. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The Surveillance is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

SR 3.4.9.3

This Surveillance is not applicable if the heaters are permanently powered by 1E power supplies.

This Surveillance demonstrates that the heaters can be manually transferred to, and energized by, emergency power supplies. The Frequency of 18 months is based on a typical fuel cycle and is consistent with similar verifications of emergency power.

REFERENCES

1. NUREG 0737, "Clarification of TMI Action Plan Requirements," November 1980.

2. Regulatory Guide 1.32, "Criteria for Safety Related Electrical Power Systems for Nuclear Power Plants," USNRC, February 1977.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The purpose of the two spring-loaded pressurizer safety valves is to provide RCS overpressure protection. Operating in conjunction with the Reactor Protection System, two valves are used to assure that the Safety Limit of 2750 psig is not exceeded for analyzed transients during operation in MODES 1 and 2. Two safety valves are used for MODE 3 and portions of MODE 4. For the remainder of MODE 4, MODE 5, and MODE 6 with the reactor head on, overpressure protection is provided by operating procedures and LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System." For these conditions the American Society of Mechanical Engineers (ASME) requirements are satisfied with one safety valve.

The self-actuated pressurizer safety valves are designed in accordance with the requirements set forth in the ASME Boiler and Pressure Vessel Code, Section III (Ref. 1). The required lift pressure is 2500 psig ± 1%. The safety valves discharge steam from the pressurizer to a quench tank located in the containment. The discharge flow is indicated by an increase in temperature downstream of the safety valves and by an increase in the quench tank temperature and level.

The upper and lower pressure limits are based on the ± 1%-tolerance requirement for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the ASME pressure limit could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

All accident analyses in the FSAR that require safety valve actuation assume operation of both pressurizer safety valves to limit increasing reactor coolant pressure. The overpressure protection analysis (Ref. 1) is also based on operation of both safety valves and assumes that the valves open at the high range of the setting (2500 psig system design pressure plus 1%). These valves must accommodate pressurizer insurges which could occur during a startup, rod withdrawal, ejected rod, loss of main feedwater, or main feedwater line break accident. The startup accident establishes the minimum safety valve capacity. The startup accident is assumed to occur at less than 15% power. Single failure of a safety valve is neither assumed in the accident analysis nor required to be addressed by the ASME Code. Compliance with this specification is required to assure that the accident analysis and design basis calculations remain valid.

The above analyses are Design Basis Accidents (DBAs) that establish the acceptance limits for the pressurizer safety valves. Reference to the analyses for these DBAs is used to assess changes to the safety valves as they relate to the acceptance limits.

The pressurizer safety valves are components that are part of the primary success path and which function or actuate to mitigate a DBA or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission-product barrier. As such, the pressurizer safety valves satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psig) and within the ASME-specified tolerance to avoid exceeding the maximum RCS design pressure Safety Limit (SL), to maintain accident analysis assumptions, and to comply with ASME Code requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The limit protected by this specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or both valves could result in exceeding the SL were a transient to occur.

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BASES (continued)

LCO (continued)

The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required while the reactor is shut down.

The Note suspending LCO 3.0.4 and SR 3.0.4 permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives good assurance that the valves are OPERABLE near their design condition. Only one valve will be removed from service at a time for testing. The [36]-hour exception is based on an 18-hour outage time for each of the two valves. The 18-hour period is derived from operating experience that hot testing can be performed in this time frame.

[For this facility, an OPERABLE pressurizer safety valve consists of the following:]

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

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

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP cut-in temperature, OPERABILITY of two valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require both safety valves for protection.

The LCO is not applicable in MODE 4 below 275°F and MODE 5 because LTOP protection is provided. Overpressure protection is not required in MODE 6 with the reactor vessel head detensioned.

(continued)

BASES (continued)

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS overpressure protection system. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the RCPB.

B.1 and B.2

If the Required Action cannot be met within the required Completion Time or if both pressurizer safety valves are inoperable, the plant must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 4 below 275°F within 12 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Similarly, the 12 hours allowed is reasonable, based on operating experience, to reach MODE 4 without challenging plant systems. Below 275°F, overpressure protection is provided by LTOP. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested one at a time and in accordance with the requirements of Section XI of the ASME Code (Ref. 1), which provides the activities and the Frequency necessary to satisfy the SRs. No additional requirements are specified.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Vessels," Section XI "Rules for Inservice Inspection of Nuclear Power Plant Components."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power-Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with three devices for pressure relief functions: two American Society of Mechanical Engineers (ASME) safety valves are safety-grade components and one PORV is not a safety-grade device. The PORV is an electromagnetic pilot-operated valve that is automatically opened at a specific set pressure when the pressurizer pressure increases and is automatically closed on decreasing pressure. The PORV may also be manually operated using controls installed in the control room.

An electric motor-operated, normally open, block valve is installed between the pressurizer and the PORV. The function of the block valve is to isolate the PORV. Block valve closure is accomplished manually using controls in the control room and may be used to isolate a leaking PORV to permit continued power operation. Most importantly, the block valve is to be used to isolate a stuck-open PORV to isolate the resulting small-break loss-of-coolant accident (LOCA). Closure terminates the RCS depressurization and coolant inventory loss.

The PORV, its block valve, and their controls are powered from normal power supplies but are also capable of being powered from emergency supplies. Power supplies for the PORV are separate from those for the block valve. Power supply requirements are defined in NUREG 0737, Paragraph III G.1 (Ref. 1).

The PORV setpoint is above the high pressure reactor trip setpoint and below the opening setpoint for the pressurizer safety valve as required by IE Bulletin 79-05B (Ref. 2). The purpose of the relationship of these setpoints is to limit the number of transient pressure increase challenges which might open the PORV, which, if opened, could fail in the open position. A pressure increase transient would cause a reactor trip, reducing core energy, and for many expected transients, prevent the pressure increase from reaching the PORV setpoint. The PORV setpoint thus limits the frequency of challenges from transients and limits the possibility of a small-break LOCA from a failed-open PORV.

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BASES (continued)

BACKGROUND (continued)

Placing the setpoint below the pressurizer safety valve opening setpoint reduces the frequency of challenges to the safety valves, which, unlike the PORV, cannot be isolated if they were to fail open. Accurate control of the PORV setpoint is therefore important for limiting the possibility of a small-break LOCA.

The primary purpose of this LCO is to ensure that the PORV, its setpoint, and the block valve are operating correctly so the potential for a small-break LOCA through the PORV pathway is minimized, or if a small-break LOCA were to occur through a failed open PORV, the block valve could be manually operated to isolate the path.

The PORV may also be manually operated to depressurize the RCS as deemed necessary by the operator in response to normal or abnormal transients. The PORV may be used for depressurization when the pressurizer spray is not available; a condition that would be encountered during loss of offsite power. Steam generator tube rupture (SGTR) is one event that may require use of the PORV if the sprays are unavailable.

The PORV may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORV functions as an automatic overpressure device and limits challenges to the safety valves. Although the PORV acts as an overpressure device for operational purposes, safety analyses [do not take credit for PORV actuation, but] do take credit for the safety valves.

The PORV also provides low temperature overpressure protection (LTOP) during heatup and cooldown. LCO 3.4.12 addresses this function.

APPLICABLE SAFETY ANALYSES

The PORV small-break LOCA break size is bounded by the spectrum of piping breaks analyzed for plant licensing. Because the PORV small-break LOCA is located at the top of the pressurizer, the RCS response characteristics are different from RCS loop piping breaks; analyses have been performed to investigate these characteristics.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The possibility of a small-break LOCA through the PORV is reduced when the PORV flow path is OPERABLE and the PORV opening setpoint is established to be reasonably remote from expected transient challenges. The possibility is minimized if the flow path is isolated.

The PORV opening setpoint has been established in accordance with Reference 2. It has been set so expected RCS pressure increases from anticipated transients will not challenge the PORV, minimizing the possibility of a small-break LOCA through the PORV.

Overpressure protection is provided by safety valves, and analyses do not take credit for the PORV opening for accident mitigation.

Operational analyses that support the emergency operating procedures utilize the PORV to depressurize the RCS for mitigation of SGTR when the pressurizer spray system is unavailable (loss of offsite power). FSAR safety analyses for SGTR have been performed assuming that offsite power is available and thus pressurizer sprays (or the PORV) are available.

The PORV and its block valve do not satisfy any specific Criterion of the NRC Interim Policy Statement. This specification was evaluated using insights gained from reviewing representative probabilistic risk assessments. The PORV and its block valve are deemed important to risk.

LCO

The LCO requires the PORV and its block valve to be OPERABLE. The block valve is required to be OPERABLE so it may be used to isolate the flow path if the PORV is not OPERABLE. If the block valve is not OPERABLE, the PORV may be used for temporary isolation.

Valve OPERABILITY also means the PORV setpoint is correct. By ensuring that the PORV opening setpoint is correct, the PORV is not subject to frequent challenges from possible pressure increase transients and therefore the possibility of a small-break LOCA through a failed-open PORV is not a frequent event.

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BASES (continued)

LCO (continued)

[For this facility, an OPERABLE pressurizer PORV and block valve consist of the following:]

[For this facility, the following support systems are required to be OPERABLE to ensure pressurizer PORV and block valve OPERABILITY:]

[For this facility, those required support systems which, upon their failure, do not require declaring the pressurizer PORV or block valve inoperable and their justification are as follows:]

APPLICABILITY

In MODES 1, 2, and 3 the PORV and its block valve are required to be OPERABLE to limit the potential for a small-break LOCA through the flow path. A likely cause for PORV LOCA is a result of pressure increase transients which cause the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. Pressure increase transients can occur any time the steam generators are used for heat removal. The most rapid increases will occur at higher operating power and pressure conditions of MODES 1 and 2.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the applicability is pertinent to MODES 1, 2, and 3. The LCO is not applicable in MODE 4 when both pressure and core energy are decreased and the pressure insurges become much less significant. The PORV setpoint is reduced for LTOP in MODES 4, 5, and 6 with the reactor vessel head in place. LCO 3.4.12 "Low Temperature Overpressure Protection (LTOP) System" addresses the PORV requirements in these MODES.

The exception for LCO 3.0.4 permits entry into MODES 1, 2, and 3 to perform cycling of the PORV or block valve to verify their operable status. Testing is typically not performed in the lower MODES.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With the PORV inoperable and capable of being manually cycled, either the PORV must be restored or the flow path isolated within 1 hour. The block valve should be closed but power must be maintained to the block valve, since removal of power would render the block valve inoperable and Condition C would apply. Although the PORV may be designated inoperable, it may be able to be manually opened and closed and therefore can be used to perform its function. PORV inoperability may be due to seat leakage, instrumentation problems, automatic control problems, or other causes that do not prevent manual use and do not create a possibility for a small-break LOCA. For these reasons the block valve may be closed, but the Action requires power be maintained to the valve. Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Times of 1 hour are based on plant operating experience that minor problems can be corrected or closure can be accomplished in this time period.

B.1, B.2.1, B.2.2, B.2.3, and B.2.4

If the PORV is inoperable and incapable of being manually cycled, it must be either restored or isolated by closing the block valve and removing the power to the block valve to preclude any inadvertent opening of the block valve at a time in which the PORV may not be closed because of maintenance. The Completion Time of 1 hour is reasonable, based on challenges to the PORVs during this time period, and provides the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, 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 6 hours and MODE 4 within the next 6 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Similarly, the 12 hours allowed is reasonable, based on operating experience, to reach MODE 4 from full power in an orderly manner and without challenging plant systems.

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BASES (continued)

ACTIONS (continued)

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

If the block valve is inoperable, it must be restored to OPERABLE status or the PORV must be placed in manual control. The prime importance for the capability to close the block valve is to isolate a stuck-open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck-open PORV at a time that the block valve is inoperable. The Completion Time of an additional hour is permitted to restore the block valve and PORV to OPERABLE status. This time is consistent with an allowance of some time for correcting minor problems, restoring the valve to operation, and establishing correct valve positions and restricting the time without PORV capability for mitigating overpressure events to short increments.

D.1 and D.2

If the Required Action cannot be met within the associated Completion Time, the plant must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Similarly, the 12 hours allowed is reasonable, based on operating experience, to reach MODE 4 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that it can be closed if needed. The basis for the frequency is ASME XI (Ref. 3). Block valve cycling, as stated in the Note, is not performed when it is closed for isolation; cycling could increase the hazard of an existing degraded flow path.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.2

SR 3.4.11.2 is the performance of a CHANNEL CALIBRATION every 18 months. The CHANNEL CALIBRATION assures that the PORV setpoint is appropriately maintained above the RCS high pressure trip setpoint and thus remote from transient pressure challenges. The calibration also assures that the PORV setpoint is below the pressurizer safety valve setpoint, thus limiting challenges to the safety valves. The calibration can only be performed during a typical refueling cycle and shutdown. The frequency of 18 months is based on a typical refueling cycle and industry-accepted practice.

SR 3.4.11.3

PORV cycling demonstrates its function. The Frequency of 18 months is based on a typical refueling cycle and industry-accepted practice.

SR 3.4.11.4

Operating the solenoid air control valves and check valves on the air accumulators ensures that the PORV Control System actuates properly when called upon. The Frequency of 18 months is based on a typical refueling cycle and the Frequency of other surveillances used to demonstrate PORV OPERABILITY.

SR 3.4.11.5

This Surveillance is not required for plants with permanent 1E power supplies to the valves.

The test demonstrates that emergency power can be provided and is performed by transferring power from the normal supply to the emergency supply and cycling the valves. The Frequency of 18 months is based on a typical refueling cycle and industry-accepted practice.

REFERENCES

1. NUREG 0737 "Clarification of TMI Action Plan Requirements," November, 1980.

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BASES (continued)

REFERENCES (continued)

2. NRC IE Bulletin 79-05B, "Nuclear Incident at Three Mile Island," April 21, 1979.

3. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary is not compromised by violating the pressure and temperature (P/T) requirements of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for providing such protection. LCO 3.4.3 provides the allowable combinations for operational P/T during cooldown, shutdown, and heatup to keep from violating the Reference 1 limits.

The vessel material is less tough at reduced temperature than at normal operating temperature. Also, as vessel neutron irradiation accumulates, the material becomes less resistant to pressure stress at low temperature (Ref. 2). RCS pressure must be maintained low when temperature is low and must be increased only as temperature is increased.

Operational maneuvering during cooldown or heatup must be controlled to not violate LCO 3.4.3 P/T limits. Exceeding these limits could lead to brittle fracture of the reactor vessel. Specification 3.4.3, "RCS Pressure and Temperature (P/T) Limits," presents requirements for administrative control of RCS P/T to prevent exceeding these limits.

This LCO provides RCS overpressure protection in the applicable MODES by ensuring an adequate pressure relief capacity and a minimum coolant addition capability. The pressure relief capacity requires either the power-operated relief valve (PORV) lift setpoint reduced and pressurizer coolant level at or below a maximum limit or the RCS depressurized and a RCS vent of sufficient size to handle the limiting transient during LTOP.

The LTOP approach to protecting the vessel by limiting coolant addition capability requires deactivating all but [one] makeup-high pressure injection (Makeup-HPI) pump, blocking HPI, and isolating the core flood tanks (CFTs).

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BASES (continued)

BACKGROUND (continued)

Should more than [one] HPI pump inject on an HPI actuation, the pressurizer level and PORV or another RCS vent cannot prevent overpressurizing the RCS. Even with only one HPI pump OPERABLE, the vent cannot prevent RCS overpressurization.

The pressurizer level limit provides a compressible vapor space or cushion (either steam or nitrogen) that can accommodate a coolant insurge and prevent a rapid pressure increase, allowing the operator time to stop the increase. The PORV, with reduced lift setting, or the RCS vent is the overpressure protection device that acts as backup to the operator in terminating an increasing-pressure event.

With HPI deactivated, the ability to provide RCS coolant addition is restricted. To balance the possible need for coolant addition, the LCO does not require the Makeup System to be deactivated. Due to the lower pressures associated with the LTOP MODES and the expected decay heat levels, the Makeup System can provide adequate flow with the OPERABLE makeup-HPI pump through the makeup control valve.

If needed in a small-break loss-of-coolant accident (small-break LOCA), the HPI function will be reactivated to open the HPI valves for one-pump injection. Plant LTOP procedures cover this abnormal condition and contain the techniques for quickly determining the small-break LOCA situation. The procedures also contain the methods for reactivating and controlling HPI to fulfill the requirements for both the small-break LOCA condition and the limited pressure relief capability of the specified RCS vent.

PORV Requirements

The PORV is signaled to open if the RCS pressure approaches a limit set in the LTOP actuation circuit. The LTOP actuation circuit monitors RCS pressure and determines when a condition not acceptable in LCO 3.4.3 limits is approached. When the monitored pressure meets or exceeds the setting, the PORV is signaled to open. The setpoint within LCO 3.4.3 limits ensures the Reference 1 limits will be met in any analyzed event.

When the PORV opens in an increasing pressure transient, the release of coolant causes the pressure increase to slow and

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BASES (continued)

BACKGROUND (continued)

reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at ambient containment pressure in an RCS overpressure transient, if the relieving requirements of the maximum credible LTOP transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow of the limiting LTOP transient and maintaining pressure below LCO 3.4.3 P/T limits. The required vent may be provided by one or more vent paths.

An RCS vent to meet the flow capacity requires removing a pressurizer safety valve, locking the PORV in the open position and disabling its block valve in the open position, or similarly establishing a vent by opening an RCS vent valve. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel can be adequately protected against overpressurization transients during shutdown. In MODES 1, 2, and 3, and in MODE 4 with RCS temperature exceeding [283]°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At nominally [283]°F and below, overpressure prevention falls to an OPERABLE PORV and a restricted coolant level in the pressurizer or to a depressurized RCS and a sufficient size RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in LCO 3.4.3 P/T limit curve falls below the pressurizer safety valve setpoint increases as vessel material toughness decreases due to neutron embrittlement. Each time LCO 3.4.3 curves

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

are revised, the LTOP System will be reevaluated to ensure that its functional requirements can still be met with the PORV and pressurizer level method or the depressurized and vented RCS condition.

Transients potentially capable of overpressurizing the RCS have been identified and evaluated. These transients relate to either mass input or heat input: actuating the HPI System, discharging the CFTs, energizing the pressurizer heaters, failing the makeup control valve open, losing decay heat removal, starting a reactor coolant pump (RCP) with a large temperature mismatch between the primary and secondary coolant systems, and adding nitrogen to the pressurizer.

HPI actuation and CFT discharge are the transients that result in exceeding RCS P/T limits within less than 10 minutes, in which time no operator action is assumed to take place. In the rest, operator action after that time precludes overpressurization. The analyses demonstrate that the time allowed for operator action is adequate, or the events are self-limiting and do not exceed LCO 3.4.3 P/T limits.

The following are required during the LTOP MODES to ensure that transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Locking out all but [one] makeup-HPI pump;

b. Blocking HPI actuation circuits;

c. Immobilizing CFT discharge isolation valves in their closed positions; and

d. Disallowing start of an RCP if secondary temperature is more than [50]°F above primary temperature in any one loop. (LCOs 3.4.6, "RCS Loops—MODE 4," and 3.4.7, "RCS Loops—MODE 5, Loops Filled," provide this protection.)

The Reference 3 analyses demonstrate the PORV can maintain RCS pressure below limits when only one HPI pump is actuated in the HPI mode. Consequently, the LCO requires only [one] makeup-HPI pump OPERABLE in the LTOP MODES.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Since the PORV cannot do this for more that one HPI pump and the RCS vent cannot do this for even one pump, the LCO also requires the HPI actuation circuits blocked and the CFTs isolated.

The isolated CFTs must have their discharge valves closed and the valve power breakers fixed in their open positions. The analyses show the effect of CFT discharge is over a narrower RCS temperature range (175°F and below) than that of the LCO ([283]°F and below).

Fracture mechanics analyses established the temperature of LTOP Applicability at [283]°F. Above this temperature, the pressurizer safety valves provide the reactor vessel pressure protection. The vessel materials were assumed to have a neutron irradiation accumulation equal to 21 effective full power years (EFPYs) of operation.

This LCO will deactivate the HPI actuation circuits when the RCS temperature is at or below [283]°F. The consequences of a small-break LOCA in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 4 and 5) requirements by having the [one] makeup-HPI pump OPERABLE and, if required by procedure, by making HPI actuation available for that pump.

Reference 3 contains the acceptance limits that satisfy the LTOP requirements. Any change to the RCS must be evaluated against these analyses to determine the impact of the change on the LTOP acceptance limits.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORV is set to open at or below [555] psig. The setpoint is derived by modelling the performance of the LTOP System, assuming the limiting allowed LTOP transient of uncontrolled HPI actuation of one pump. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoint at or below the derived limit ensures the Reference 1 limits will be met.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The PORV setpoint will be re-evaluated for compliance when the revised P/T limits conflict with the LTOP analysis limits. LCO 3.4.3 P/T limits are periodically modified as the reactor vessel material toughness dec[illegible]s due to embrittlement induced by neutron irradi[illegible] Revised P/T limits are determined using neutron fl[illegible]jections and the results of examinations of the re[illegible]l material irradiation surveillance specimens. [illegible] for LCO 3.4.3, "RCS Pressure and Temperat[illegible] Limits," discuss these examinations.

The PORV is considered an active component. Therefore, its failure represents the worst-case LTOP sing[illegible] failure.

<u>Pressurizer Level Performance</u>

Analyses of operator response time show that the pressurizer level must be maintained at or below [2.0] inches to provide the 10-minute action time for correcting transients.

The pressurizer level limit will also be re-evaluated for compliance each time LCO 3.4.3 P/T limit curves are revised based on the results of the vessel material surveillance.

<u>RCS Vent Performance</u>

With the RCS depressurized, analyses show a vent of [0.75] square inches is capable of mitigating the transient resulting from full opening of the makeup control valve while the makeup-HPI pump is providing RCS makeup. The capacity of a vent this size is greater than the flow resulting from this credible transient at 100 psig back pressure, which is less than the maximum RCS pressure on the P/T limit curve in LCO 3.4.3.

The RCS vent size will also be re-evaluated for compliance each time LCO 3.4.3 P/T limit curves are revised based on the results of the vessel material surveillance. The vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

The LCO requires an LTOP System OPERABLE with a minimum coolant input capability and a pressure relief capability To limit coolant input, it requires only [one] makeup-HPI pump OPERABLE, the HPI actuation circuits blocked, and the CFT discharge isolation valves closed and immobilized. For pressure relief, it requires either the pressurizer coolant at or below a maximum level and the PORV OPERABLE with a lift setting at the LTOP limit or the RCS depressurized and a vent established.

Specification 3.5.3, "ECCS—Shutdown," defines the pump OPERABILITY requirements. (Specification 3.3.5, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," defines HPI actuation OPERABILITY for the LTOP MODE 4 small-break LOCA, when enabled by procedure as discussed in the previous section.)

The pressurizer is OPERABLE with a coolant level at or below [220] inches.

The PORV is OPERABLE when its block valve is open, its lift setpoint is set at [555] psig or less and testing has proven its ability to open at that setpoint, and motive power is available to the two valves and their control circuits. [For this facility, the power support systems for the PORV, its block valve, and their controls are as follows:]

For the depressurized RCS, a RCS vent is OPERABLE when open with an area of at least [0.75] square inches.

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

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

APPLICABILITY

This LCO is applicable in MODE 4 when the RCS temperature is less than or equal [283]°F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The Applicability temperature of [283]°F is established by fracture mechanics

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BASES (continued)

APPLICABILITY (continued)

analyses. The pressurizer safety valves provide overpressure protection to meet LCO 3.4.3 P/T limits above [283]°F. With the vessel head off, overpressurization is not possible.

LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the pressurizer safety valves OPERABLE to provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above [283]°F.

The Applicability is modified by a Note stating that CFT isolation is only required when the CFT pressure is more than or at the RCS pressure for the existing temperature, as allowed in LCO 3.4.3. This Note permits the CFT discharge valve surveillance performed only under these P/T conditions.

ACTIONS

A.1 and B.1

With more than [one] makeup-HPI OPERABLE or the HPI circuitry unblocked, immediate actions are required to render the other pump(s) inoperable or to block HPI. Emphasis is on immediate deactivation because inadvertent injection with more than [one] HPI pump OPERABLE is the event of greatest significance, since it causes the greatest pressure increase in the shortest time. Also, the vent cannot mitigate overpressurization from the injection of even one HPI pump.

The Completion Times of "immediately" reflect the urgency of quickly proceeding with the Required Actions.

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

A CFT unisolated requires isolation within 1 hour only when the CFT pressure is at or more than the maximum RCS pressure for the existing temperature allowed in LCO 3.4.3.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1 and Required Action D.2 provide two

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BASES (continued)

ACTIONS (continued)

options, either of which must be performed in 12 hours. By increasing the RCS temperature to more than 175°F, the CFT pressure of 600 psig cannot exceed the LTOP limits if both tanks are fully injected. Depressurizing the CFTs below the LTOP limit of [555] psig also prevents exceeding the LTOP limits in the same event.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations (Ref. 6) indicating that a limiting LTOP event is not likely in the allowed times.

E.1, F.1, and F.2

With the pressurizer level more than [220] inches, the time for operator action in a pressure-increasing event is reduced. The postulated event most affected in the LTOP MODES is failure of the makeup control valve, which fills the pressurizer relatively rapidly. Restoration is required within 1 hour.

Pressurizer level is considered not within the LTOP limit if the equipment used to verify the level is determined inoperable. Required Action E.1 applies to restoring such equipment to OPERABLE status.

If restoration within 1 hour in either case cannot be accomplished, Required Actions F.1 and F.2 must be performed within 12 hours to close the makeup control valve and its isolation valve. These Actions limit the makeup capability, which is not required with a high pressurizer level, and permit cooldown and depressurization to continue. Heatup must be stopped because heat addition decreases the reactor coolant density and increases the pressurizer level.

The Completion Times again consider operating experience that these activities can be accomplished in these time periods and engineering evaluations showing that a limiting LTOP transient is not likely in the those times.

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

With the PORV inoperable, overpressure relieving capability is lost, and restoration of the PORV within 1 hour

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BASES (continued)

ACTIONS (continued)

is required. If that cannot be accomplished, the ability of the Makeup System to add water must be limited within the next 11 hours.

If restoration cannot be completed within 1 hour, Required Action H.1 and Required Action H.2 must be performed to limit RCS water addition capability. Makeup is not deactivated to maintain the RCS coolant level. Required Action H.1 and Required Action H.2 require reducing the makeup tank level to 70 inches and deactivating the low-low makeup tank level interlock to the borated water storage tank. This makes the available makeup water volume insufficient to exceed the LTOP limit by a makeup control valve full opening.

These Completion Times also consider these activities can be accomplished in these time periods, and Reference 6 shows a limiting LTOP event is not likely in those times.

Some PORV testing or maintenance can only be performed at plant shutdown. Such activity is permitted if Required Action H.1 and Required Action H.2 are taken to compensate for PORV unavailability.

I.1 and I.2.

With the pressurizer level above [220] inches and the PORV inoperable or the LTOP System is inoperable for any reason other than cited in Condition A through H, the system must be restored to OPERABLE status within 1 hour. When this is not possible, Action I.2.1 requires the RCS depressurized and vented in 12 hours from the time either Condition started.

One or more vents may be used. A vent size of [0.75] square inches is specified. This vent size assumes 100 psig backpressure. Because makeup may be required, the vent size accommodates inadvertent full makeup system operation. Such a vent keeps the pressure from full flow of [one] makeup-HPI pump with a wide-open makeup control valve within the LCO limit.

The PORV has a larger area and may be used for venting by opening and locking it open. This is preferable in case

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BASES (continued)

ACTIONS (continued)

of having to unblock HPI for a small-break LOCA event. The PORV vent would meet the LTOP pressure limit without further control of a HPI in progress.

This size RCS vent or the PORV as a vent cannot maintain RCS pressure below LTOP limits if the HPI and CFT systems are inadvertently actuated. Therefore, verification of the deactivation of two HPI pumps, HPI injection, and the CFTs must accompany the depressurizing and venting. Since those systems are required deactivated by the LCO, SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 require verification of their deactivated status every 12 hours.

Again, the Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that a limiting LTOP transient is not likely in those times.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

Verifications must be performed that only [one] makeup-HPI pump is OPERABLE and the other two HPI pumps are locked out with power removed, the HPI actuation circuits are blocked, and the CFT discharge isolation valves are closed and immobilized. These Surveillances ensure the minimum coolant input capability will not create an RCS overpressure condition to challenge the LTOP System. The Surveillances are first required within 15 minutes before decreasing RCS temperature to or below [283]°F in MODE 4; thereafter, at 12-hour intervals. The surveillance for the CFTs is only required when the CFT pressure is at or more than the maximum RCS pressure for the existing temperature allowed in LCO 3.4.3.

The 15-minute intervals are adequate from operating experience to verify minimum coolant input capability and ensure this LCO requirement is satisfied before entering the applicable MODE. The 12-hour intervals are shown by operating practice to be sufficient to regularly assess conditions for potential degradation and verify operation within the safety analysis.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

Verification of the pressurizer level at or less than [220] inches by observing control room or other indications assures a cushion of sufficient size is available to reduce the rate of pressure increase from potential transients. [For this facility, pressurizer level is measured as follows:]

The 30-minute Surveillance Frequency during heatup and cooldown must be performed for the LCO Applicability period when temperature changes can cause pressurizer level variations. This Frequency may be discontinued when the ends of these conditions are satisfied, as defined in plant procedures. Thereafter, the Surveillance is required at 12-hour intervals.

These Surveillance Frequencies are shown by operating practice sufficient to regularly assess indications of potential degradation and verify operation within the safety analysis.

SR 3.4.12.5

Verification that the PORV block valve is open ensures a flow path to the PORV. This is required at 12-hour intervals.

The interval has been shown by operating practice sufficient to regularly assess conditions for potential degradation and verify operation is within the safety analysis.

SR 3.4.12.6

When stipulated by Required Action I.2.1, the RCS vent of at least [0.7] square inches must be verified open for relief protection. For a vent valve not locked open, the Surveillance Frequency is every 12 hours. For a valve locked open, the required Frequency is every 31 days.

Again, the Frequency intervals consider operating practice to determine adequacy to regularly assess conditions for potential degradation and verify operation within the safety analysis.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.7

A CHANNEL FUNCTIONAL TEST is required within [12] hours after decreasing RCS temperature to $\leq$ [283]°F and every 31 days thereafter to ensure the setpoint is proper for using the PORV for LTOP. PORV actuation is not needed, as it could depressurize the RCS.

The [12]-hour Frequency considers the unlikelihood of a low-temperature overpressure event during the time. The 31-day Frequency is based on industry-accepted practice and is acceptable by experience with equipment reliability.

A Note makes SR 3.0.4 not applicable. The test cannot be performed until the plant is in the LTOP MODES since the PORV lift setting must be reduced for use in LTOP.

SR 3.4.12.8

The performance of a CHANNEL CALIBRATION is required every [18] months. The CHANNEL CALIBRATION for the LTOP setpoint ensures that the PORV will be actuated at the appropriate RCS pressure by verifying the accuracy of the instrument string. The calibration can only be performed in shutdown.

The Frequency considers a typical refueling cycle and industry-accepted practice.

REFERENCES

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

2. Generic Letter 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operation."

3. [Unit Name] FSAR, Section [15.], "[Title]."

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

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS. The RCS components, including the portions of the connecting systems out to and including the isolation valves, define the reactor coolant pressure boundary (RCPB).

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 system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE and the methods used to identify and quantify them.

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.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area are necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is needed to provide quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the facility and the public.

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

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to

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BASES (continued)

BACKGROUND (continued)

preventing the accident analysis radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss-of-coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

Except for primary-to-secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 1 gpm primary-to-secondary LEAKAGE as the initial condition.

Primary-to-secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leak contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is only briefly released via safety valves and the majority is steamed to the condenser. The 1-gpm primary-to-secondary LEAKAGE is relatively inconsequential.

The SLB is more limiting for site radiation releases. The safety analysis for the SLB accident assumes 1 gpm primary-to-secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 100 or the staff-approved licensing basis (i.e., a small fraction of these limits).

The above analyses are for Design Basis Accidents (DBAs) that establish the acceptance limits for RCS operational LEAKAGE. Reference to the analyses for these DBAs is used to assess changes to the facility which could affect LEAKAGE as they relate to the acceptance limits.

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

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BASES (continued)

LCO

a. No Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE.

Violation of this LCO could result in continued degradation of the RCPB.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of identified LEAKAGE and is well within the capability of the RCS makeup system. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary-to-Secondary LEAKAGE through All Steam Generators (SGs)

Total primary-to-secondary LEAKAGE through all SGs of 1 gpm produces acceptable offsite doses in the steam line break accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary-to-secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

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BASES (continued)

LCO (continued)

e. Primary-to-Secondary LEAKAGE through One SG

The 720 gallon per day (gpd) limit on one SG allocates the total 1-gpm allowed primary- to-secondary LEAKAGE equally between the two generators.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.15, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary-to-secondary LEAKAGE in excess of the LCO limits must be reduced within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists or if unidentified, identified, or primary-to-secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. The reactor

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BASES (continued)

ACTIONS (continued)

must be placed in MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The Completion Times of 6 hours to reach MODE 3 and 36 hours to reach MODE 5 from full power are reasonable, based on operating experience, to reach the required conditions from full power in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE within the LCO limits assures that the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of a RCS water inventory balance. Primary-to-secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The RCS water inventory balance must be performed with the reactor at steady-state operating conditions and near operating pressure. Therefore, the requirement of SR 3.0.4 is not applicable for performing an RCS inventory balance before entering MODE 4 or MODE 3.

Steady-state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and the Surveillance is not required unless steady state is established. For RCS operational LEAKAGE determination by inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP pump seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

the containment sump level. These LEAKAGE detection systems are specified in LCO 3.4.15, "RCS LEAKAGE Detection Instrumentation."

The 72-hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leak detection in the prevention of accidents.

SR 3.4.13.2

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 and adequately verifies RCPB integrity.

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. [Unit Name] FSAR, Section [15], "[Accident Analysis.]"

3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 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) which separate the high pressure RCS from an attached low pressure system. 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 permits 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 both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by an inventory balance (SR 3.4.13.1) and identification of excessive unidentified LEAKAGE while implementing Required Action A.1 of LCO 3.4.13. A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leak tight.

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. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A

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BASES (continued)

BACKGROUND (continued)

subsequent study (Ref. 5) 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.

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

a. Decay Heat Removal (DHR) System [including the core flood tanks];

[b. High pressure injection (HPI) System]; and

[c. Makeup and Purification System].

For this facility, the PIVs are listed in Reference 6.

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

Reference 4 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 DHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB and the subsequent pressurization of the DHR System downstream of the PIVs from the RCS. Because the low pressure portion of the DHR System is typically designed for [600] psig, overpressurization failure of the DHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 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.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	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. These analyses establish the acceptance limits for RCS PIV leakage. Reference to these analyses is used to assess changes to the facility which could affect RCS PIV leakage as they relate to the acceptance limits. Since it must be included as part of identified LEAKAGE covered by LCO 3.4.13, "RCS Operational LEAKAGE," RCS PIV leakage satisfies Criterion 2 of the NRC Interim Policy Statement.
LCO	RCS PIV Leakage is identified 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 (Ref. 7). 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. Studies concluded that a leak rate limit based on valve size was superior to a single allowable value. (continued)

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BASES (continued)

LCO (continued)

Reference 7 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 that leakage is directly proportional to the pressure differential to the one-half power.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

In MODES 5 and 6, 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.

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 leakage is assessed and corrective actions are taken. The 4 hours allow the actions and restrict the operation with leaking isolation valves.

Alternatively, the flow path must be isolated by two valves. Required Actions A.2.1 and 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. 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 some other 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.

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BASES (continued)

ACTIONS (continued)

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 3.4.14.1 is performed. Required 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 within the respective Completion Time, the plant must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in MODE 3 within 6 hours and MODE 5 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 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve 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 a 5-gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

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 5 for at least 7 days. The 18-month Frequency, as required in 10 CFR 50.55a(g) (Ref. 8), is within the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 9) and is based on the prudence of performing surveillances like 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.

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 the valve.

SR 3.0.4 is excepted for entry into MODES 3 and 4 to permit leak testing at high differential pressures with stable conditions not possible in the lower MODES.

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

SR 3.4.14.2 and SR 3.4.14.3

Verifying that the [DHR] autoclosure interlocks are OPERABLE ensures that RCS pressure will not pressurize the [DHR] System beyond 125% of its design pressure of [600] psig. The interlock setpoint that prevents the valves from being opened is set so that the actual RCS pressure must be less than [425] psig to open the valves. This setpoint ensures that the [DHR] design pressure will not be exceeded and that the [DHR] relief valves will not lift. The Frequency of [18 months] is based on engineering judgment and the fact that the testing of these interlocks is best performed during a refueling outage. This Frequency has been shown to be acceptable through operating experience.

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," General Design Criterion 55, "Reactor Coolant Pressure Boundary Penetrating Containment."

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BASES (continued)

REFERENCES (continued)

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

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

6. [ ]

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

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

9. 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 3.4.15 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 detection systems.

LEAKAGE detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can readily be detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE is [(or) and air cooler condensate are] instrumented to alarm for increases of 0.5 to 1.0 gpm in the normal flow rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring and of 10^{-6} μCi/cc radioactivity for gaseous monitoring are practical for these LEAKAGE detection systems. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew-point temperature measurements can thus be used to monitor

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BASES (continued)

BACKGROUND (continued)

humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated LEAKAGE rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump [and condensate flow from air coolers]. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS LEAKAGE into the containment. The relevance of temperature and pressure measurements are affected by containment-free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable LEAKAGE to the containment.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the FSAR (Ref. 3). Multiple instrument locations are utilized, if needed, to ensure the transport delay time of the LEAKAGE from its source to an instrument location yields an acceptable overall response time.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the facility and the public.

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

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BASES (continued)

LCO

One method of protecting against large RCS LEAKAGE derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a particulate or gaseous activity monitor [and a containment air cooler condensate flow rate monitor], provides an acceptable minimum.

[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

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS LEAKAGE detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, LEAKAGE and the likelihood of crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

<u>A.1 and A.2</u>

With the containment sump monitor inoperable, no form of grab sample could provide the equivalent information.

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BASES (continued)

ACTIONS (continued)

However, the containment atmosphere activity monitor will provide indications of changes in LEAKAGE. Together with the atmosphere monitor, the periodic surveillance for RCS inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect LEAKAGE.

Restoration of the sump monitor to OPERABLE status is required to regain the function in a Completion Time of 30 days after the monitor's failure. This time is acceptable considering the frequency and adequacy of the RCS inventory balance required by Action A.1.

B.1.1, B.1.2, and B.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. With a sample obtained and analyzed or an inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of at least one of the radioactivity monitors.

The 24-hour interval provides periodic information that is adequate to detect LEAKAGE. The 30-day Completion Time recognizes at least one other ready form of leak detection.

C.1 and C.2

If a Required Action of Condition A or B [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 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable based on operating experience to perform the actions without challenging plant systems.

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BASES (continued)

ACTIONS (continued)

D.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 3.4.15.1 and SR 3.4.15.2

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

SR 3.4.15.3 and SR 3.4.15.4

These SRs are the performance of an ANALOG CHANNEL OPERATIONAL TEST [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, an ANALOG CHANNEL OPERATIONAL TEST [a CHANNEL FUNCTIONAL TEST] consists of [ ].

SR 3.4.15.5 and SR 3.4.15.6

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 [ ].

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BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 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," U.S. Nuclear Regulatory Commission.

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The Code of Federal Regulations, 10 CFR 100 (Ref. 1) specifies the maximum dose to the whole body and the thyroid an individual at the site boundary can receive for 2 hours during an accident. The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2-hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline values. The limits in the LCO are standardized based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR accident were an appropriately small fraction of the 10 CFR 100 guideline dose limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting 2-hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guidelines (Ref. 1) following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limits and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm. The analysis also assumes a reactor trip and a turbine trip at the same time as the SGTR event.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the facility which could affect RCS specific activity as they relate to the acceptance limits.

The rise in pressure in the ruptured SG causes radioactively contaminated steam to discharge to the atmosphere through the atmospheric dump valves or the main steam safety valves. The atmospheric discharge stops when the turbine bypass to the condenser removes the excess energy to rapidly reduce the RCS pressure and close the valves. The unaffected SG removes core decay heat by venting steam until the cooldown ends.

The safety analysis shows the radiological consequences of a SGTR accident are within a small fraction of the Reference 1 dose guideline values. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1 for more than 48 hours.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a SGTR accident occurring during the established 48-hour time limit. The occurrence of a SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline values.

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

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the total specific activity in the primary coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2-hour thyroid dose to an individual at the site boundary during the Design Basis Accident (DBA) will be a small fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2-hour whole body dose to an

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BASES (continued)

LCO (continued)	individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose. The SGTR accident analysis (Ref. 2) shows that the 2-hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a SGTR, lead to site boundary doses that exceed the 10 CFR 100 guideline values.
APPLICABILITY	In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and total specific activity are necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values. For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of an SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the atmospheric dump valves and main steam safety valves.
ACTIONS	A.1 and A.2 With the gross specific activity in excess of the allowed limit, an analysis must be performed within 4 hours to determine DOSE EQUIVALENT I-131. The Completion Time of 4 hours is required to obtain and analyze a sample. The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the set points of the main steam safety valves, and prevents venting the SG to the environment in an SGTR event. The Completion Time of 6 hours is required to reach MODE 3 from full power in an orderly manner and without challenging reactor emergency systems.

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BASES (continued)

ACTIONS (continued)

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 3.4.16.1 is performed. Required Actions A.1 and A.2 apply to restoring such equipment to OPERABLE status.

B.1 and B.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals not to exceed 4 hours must be taken to demonstrate the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling must continue for trending.

The DOSE EQUIVALENT I-131 must be restored to normal within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

DOSE EQUIVALENT I-131 specific activity is considered out of limits if the equipment used to measure DOSE EQUIVALENT I-131 is determined to be inoperable at the time SR 3.4.16.2 is performed. Required Actions B.1 and B.2 apply to restoring such equipment to OPERABLE status.

C.1

The reactor must be placed in MODE 3 with RCS average temperature < 500°F within 6 hours, when a Required Action and associated Completion Time of Condition B are not met or the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1. The Completion Time of 6 hours is required to get to MODE 3 below 500°F without challenging reactor emergency systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

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

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 the time.

SR 3.4.16.2

This Surveillance is performed 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 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 3.4.16.3

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. The Frequency of 184 days recognizes E does not change rapidly.

SR 3.0.4 does not apply so that sampling can be performed in MODE 1. The sample must be taken after 2 effective full power days (EFPDs) 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.

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BASES (continued)

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 [15.6.3], "[Title]."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Core Flood Tanks (CFTs)

BASES

BACKGROUND

The function of the ECCS CFTs is to supply water to the reactor vessel during the blowdown phase of a loss-of-coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small-break LOCA. Two CFTs are provided for these functions.

The blowdown phase of a large-break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission-product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which follows immediately, reactor coolant inventory has vacated the core through steam flashing and ejection out the beak. The core is essentially in adiabatic heatup. The balance of inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection water.

The CFTs are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The CFTs are passive components, since no operator or control actions are required for them to perform their function. Internal tank pressure is sufficient to discharge the contents of the CFTs to the RCS if RCS pressure decreases below the CFT pressure. Each CFT is piped separately into the reactor vessel downcomer. The CFT injection lines are also utilized by the Low Pressure Injection (LPI) System. Each CFT is isolated from the RCS by a motor-operated isolation valve and two check valves in series.

The motor-operated isolation valves are normally open, with power removed from the valve motor to prevent inadvertent closure prior to or during an accident. Additionally, the valves are interlocked with RCS pressure to ensure that they

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BASES (continued)

BACKGROUND (continued)

will open automatically as RCS pressure is increased above CFT pressure and to prevent inadvertent closure prior to an accident. The valves also receive an Engineered Safety Feature Actuation System (ESFAS) signal to open. These features ensure that the valves meet the requirement of the Institute of Electrical and Electronic Engineers (IEEE) Standard 279-1971 for "operating bypasses" and that the CFTs will be available for injection without reliance on operator action.

The CFTs thus form a passive system for injection directly into the reactor vessel. Except for the core flood line break LOCA, a unique accident that also disables a portion of the injection system, both tanks are assumed to operate in the safety analyses for design basis events. Because injection is directly into the reactor vessel downcomer, and because it is a passive system not subject to the single active failure criterion, all fluid injection is credited for core cooling.

The CFT gas/water volumes, gas pressure, and outlet pipe size are selected to provide core cooling for a large-break LOCA prior to the injection of coolant by the LPI System.

APPLICABLE SAFETY ANALYSES

The CFTs are taken credit for in both the large- and small-break LOCA analyses at full power (Ref. 1). These Design Basis Accident (DBA) analyses establish the acceptance limits for the CFTs. Reference to the analyses for these DBAs is used to assess changes in the CFTs as they relate to the acceptance limits. In performing the LOCA calculations, conservative assumptions are made concerning the availability of emergency injection flow. The assumption of the loss of offsite power is required by regulations. In the early stages of a LOCA with the loss of offsite power, the CFTs provide the sole source of makeup water to the RCS.

This is because the LPI pumps and high pressure injection (HPI) pumps cannot deliver flow until the emergency diesel generators (EDGs) start, come to rated speed, and go through their timed loading sequence.

The limiting large-break LOCA is a double-ended guillotine cold leg break at the discharge of the reactor coolant pump.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

During this event, the CFTs discharge to the RCS as soon as RCS pressure decreases below CFT pressure. As a conservative estimate, no credit is taken for HPI for large-break LOCA. LPI is not assumed to occur until 35 seconds after the RCS pressure decreases to the ESFAS actuation pressure. No operator action is assumed during the blowdown stage of a large-break LOCA.

The small-break LOCA analysis also assumes a time delay after ESFAS actuation before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated by the CFTs, with pumped flow then providing continued cooling. As break size decreases, the CFTs and HPI pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the CFTs continues to decrease until the tanks are not required and the HPI pumps become responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established by 10 CFR 50.46 (Ref. 2) for the ECCS will be met following a LOCA:

a. Maximum fuel element cladding temperature of 2200°F;

b. Maximum cladding oxidation of $\leq$ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium-water reaction of $\leq$ 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; and

d. Core maintained in a coolable geometry.

Since the CFTs discharge during the blowdown phase of a LOCA, they do not contribute to the long-term cooling requirements of 10 CFR 50.46.

The limits for operation with a CFT that is inoperable for any reason other than the boron concentration not being within limits minimize the time that the plant is exposed to a LOCA event occurring concurrent with failure of a CFT,

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

which might result in unacceptable peak cladding temperatures. If a closed isolation valve cannot be opened, or the proper water volume or nitrogen cover pressure cannot be restored, the full capability of one CFT is not available and prompt action is required to place the reactor in a MODE in which this capability is not required.

In addition to LOCA analyses, the CFTs have been assumed to operate to provide borated water for reactivity control for severe overcooling events such as a large steam line break (SLB).

The CFTs are part of the primary success path that functions or actuates to mitigate a DBA that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

The minimum volume requirement for the CFTs ensures that both CFTs can provide adequate inventory to reflood the core and downcomer following a LOCA. The downcomer then remains flooded until the HPI and LPI systems start to deliver flow.

The maximum volume limit is based upon the need to maintain adequate gas volume to ensure proper injection, ensure the ability of the CFTs to fully discharge, and limit the maximum amount of boron inventory in the CFTs. The safety analysis assumes values of [ ] and [ ]. To allow for instrument accuracy, values of 7555 gallons and 8005 gallons are specified. Values of other parameters are treated similarly.

The minimum nitrogen cover pressure requirement of [525] psig ensures that the contained gas volume will generate discharge flow rates during injection that are consistent with those assumed in the safety analysis.

The maximum nitrogen cover pressure limit of [625] psig ensures that the amount of CFT inventory that is discharged while the RCS depressurizes, and is therefore lost through the break, will not be larger than that predicted by the safety analysis. The maximum allowable boron concentration of [3500] ppm in the CFTs ensures that the sump pH will be maintained between 7.0 and 11.0 following a LOCA.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The minimum boron requirement of [2270] ppm is selected to ensure that the reactor will remain subcritical during the reflood stage of a large-break LOCA. During a large-break LOCA, all control rod assemblies are assumed not to insert into the core and the initial reactor shutdown is accomplished by void formation during blowdown. Sufficient boron concentration must be maintained in the CFTs to prevent a return to criticality during reflood.

The CFT isolation valves are not single failure proof; therefore, whenever these valves are open, power shall be removed from them. This precaution ensures that both CFTs are available during an accident. With power supplied to the valves, a single active failure could result in a valve closure, which would render one CFT unavailable for injection. Both CFTs are required to function for a large-break LOCA.

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

LCO

The LCO establishes the minimum conditions required to ensure that the CFTs are available to accomplish their core cooling safety function following a LOCA. Both CFTs are required to function for a large-break LOCA. If the entire contents of both tanks are not injected during the blowdown phase of a large-break LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated. For a CFT to be considered OPERABLE, the isolation valve must be fully open, with power removed, and the limits established in the SR for contained volume, boron concentration, and nitrogen cover pressure must be met.

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

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

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BASES (continued)

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure $\geq$ 750 psig, the CFT OPERABILITY requirements are based on full power operation. Although cooling requirements may decrease as power decreases, the CFTs are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures above $\geq$ 750 psig. Below 750 psig, the rate of RCS blowdown is such that the safety injection pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

In MODE 3 $\leq$ 750 psig, and in MODES 4, 5, and 6, the CFT motor-operated isolation valves are closed to isolate the CFTs from the RCS. This allows RCS cooldown and depressurization without discharging the CFTs into the RCS or requiring depressurization of the CFTs.

A Note has been included to provide clarification that all the Conditions A and B are treated as an entity for this LCO with a single Completion Time.

ACTIONS

A.1

If the boron concentration of one CFT is not within limits, it must be returned to within the limits within 72 hours. In this condition, ability to maintain subcriticality may be reduced, but the effects of reduced boron concentration on core subcriticality during reflood are minor. Boiling of the ECCS water in the core during reflood concentrates the boron in the saturated liquid that remains in the core. In addition, the volume of the CFT is still available for injection. Since the boron requirements are based on the average boron concentration of the total volume of two CFTs, the consequences are less severe than they would be if the contents of a CFT were not available for injection. Thus, 72 hours is allowed to return the boron concentration to within limits.

The ECCS CFT boron concentration is considered out of limits if the equipment used to verify concentration is determined to be inoperable at the time SR 3.5.1.4 is performed.

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BASES (continued)

ACTIONS (continued)

Required Action A.1 applies to restore such equipment to OPERABLE status.

B.1

If one CFT is inoperable, for a reason other than boron concentration, the CFT must be returned to OPERABLE status within 1 hour. In this condition, it cannot be assumed that the CFT will perform its required function during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 1-hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action is taken to return the inoperable CFT to OPERABLE status. The Completion Time minimizes the time the plant is potentially exposed to a LOCA in these conditions.

The ECCS CFT borated water volume and nitrogen cover pressure are considered out of limits if the equipment used to verify these parameters is determined to be inoperable at the time SR 3.5.1.2 (volume) or SR 3.5.1.3 (pressure) is performed. Required Action B.1 applies to restore such equipment to operable status.

C.1 and C.2

If the CFT cannot be returned 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 6 hours and by reducing RCS pressure to $\leq$ 750 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power in an orderly manner and without challenging plant systems.

D.1

If more than one CFT is inoperable, the plant is in a condition outside the accident analysis; therefore, LCO 3.0.3 must be entered immediately.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Verification every 12 hours that each CFT isolation valve is fully open, as indicated in the control room, ensures that the CFTs are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor-operated valve position should not change with power removed, a closed valve could result in accident analysis assumptions not being met. A 12-hour Frequency is considered reasonable in view of administrative controls, such as valve position indications available to the operator, that ensure that a mispositioned isolation valve will be quickly identified and limit the time the plant would be operated with the CFT isolated.

SR 3.5.1.2 and SR 3.5.1.3

Verification every 12 hours of each CFT's nitrogen cover pressure and the borated water volume is sufficient to ensure adequate injection during a LOCA. Due to the static design of the CFTs, a 12-hour Frequency usually allows the operator to identify changes before the limits are reached. Operating experience has shown that this Frequency is appropriate for early detection and correction of off-normal trends. In addition, alarms also signify off-normal conditions.

[For this facility, a CFT's borated water volume and nitrogen cover pressure are measured as follows:]

SR 3.5.1.4

Once every 31 days for verification that the CFT boron concentration is within the required limits is reasonable because the static design of the CFT limits the ways in which the concentration can be changed. The Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage. Sampling within 6 hours after an 80-gallon volume increase will identify whether inleakage from the RCS has caused a reduction in boron concentration to below the required

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

limit. It is not necessary to verify boron concentration if the added water inventory is from the borated water storage tank (BWST), because the water contained in the BWST is within CFT boron concentration requirements.

[For this facility, a CFT's boron concentration is measured as follows:]

SR 3.5.1.5

Verification every 31 days that power is removed from each CFT isolation valve operator ensures that an active failure could not result in the undetected closure of a CFT motor-operated isolation valve coincident with a LOCA. If this closure were to occur, the contents of only one CFT would be available for injection given a single failure coincident with a LOCA. Installation and removal of locks on the breaker are conducted under administrative control. Since this is a verification that the breaker has been locked in the open position, a 31-day Frequency was chosen to provide additional assurances that the breaker is locked.

This SR is modified by a Note that allows power to be supplied to the motor-operated isolation valves when RCS pressure is < [2000] psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns. Even with power supplied to the valves, inadvertent closure is prevented by the RCS pressure interlock associated with the valves. Should closure of the valve occur, in spite of interlock, the ESFAS signal provided to the valves would open a closed valve in the event of a LOCA.

REFERENCES

1. [Unit Name] FSAR, Section 6.3, "Emergency Core Cooling System."

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

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS—Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling to ensure that the reactor core is protected after any of the following accidents:

1. Loss-of-coolant accident (LOCA);
2. Rod ejection accident (REA); and
3. Steam generator tube rupture (SGTR).

There are two phases of ECCS operation: injection and recirculation. In the injection phase, all injection is initially added to the Reactor Coolant System (RCS) via the cold legs and to the reactor vessel. After the borated water storage tank (BWST) has been depleted, the ECCS recirculation phase is entered as the ECCS suction is transferred to the containment sump.

Two redundant, 100% capacity trains are provided. In MODES 1, 2, and 3, each train consists of high pressure injection (HPI) and low pressure injection (LPI) subsystems. In MODES 1, 2, and 3, both trains must be OPERABLE. This ensures that 100% of the core cooling requirements can be provided even in the event of a single active failure.

A suction header supplies water from the BWST or the containment sump to the ECCS pumps. Separate piping supplies each train. HPI discharges into each of the four RCS cold legs between the reactor coolant pump and the reactor vessel. LPI discharges into each of the two core flood nozzles on the reactor vessel that discharge into the vessel downcomer area. Control valves are set to balance the HPI flow to the RCS. This flow balance directs sufficient flow to the core to meet the analysis assumptions following a small-break LOCA in one of the RCS cold legs near a HPI nozzle.

The HPI pumps are capable of discharging to the RCS at an RCS pressure above the opening setpoint of the pressurizer safety valves. The LPI pumps are capable of discharging to

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BASES (continued)

BACKGROUND (continued)

the RCS at an RCS pressure of approximately 200 psia. When the BWST has been nearly emptied, the suction for the LPI pumps is manually transferred to the containment sump. The HPI pumps cannot take suction directly from the sump. If HPI is still needed, a cross-connect from the discharge side of the LPI pump to the suction of the HPI pumps would be opened. This is known as "piggy backing" HPI to LPI and enables continued HPI to the RCS, if needed, after the BWST is emptied.

In the long-term cooling period, flow paths in the LPI System are established to preclude the possibility of boric acid in the core region reaching an unacceptably high concentration. One flow path is from the hot leg through the decay heat suction line from the hot leg and then in a reverse direction through the containment sump outlet line into the sump. The other flow path is through the pressurizer auxiliary spray line from one LPI train into the pressurizer and through the hot leg into the top region of the core. Either flow path prevents concentration of boric acid to unacceptably high levels.

The HPI subsystem also functions to supply borated water to the reactor core following increased heat removal events, such as large steam line breaks (SLBs).

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

During a large-break LOCA, RCS pressure will decrease to < 200 psia in less than 20 seconds. The ECCS is actuated upon receipt of an Engineered Safety Feature Actuation System (ESFAS) signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately (in the programmed sequence). If offsite power is not available, the engineered safety feature (ESF) buses shed normal operating loads and are connected to the diesel generators. Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting

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BASES (continued)

BACKGROUND (continued)

determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive Core Flood Tanks (CFTs) and the BWST covered in LCO 3.5.1, "Core Flood Tanks (CFTs)," and LCO 3.5.4, "Borated Water Storage Tank (BWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

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

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

d. Core is maintained in a coolable geometry; and

e. Adequate long-term core cooling capability is maintained.

The LCO also ensures that containment temperature limits are met.

Both HPI and LPI subsystems are assumed to be OPERABLE in the large-break LOCA analysis at full power (Ref. 3). This analysis establishes a minimum required flow for the HPI and LPI pumps, as well as the minimum required response time for their actuation. The HPI pump is credited in the small-break LOCA analysis. This analysis establishes the flow and discharge head requirements at the design point for the HPI pump. The SGTR and SLB analyses also credit the HPI pump but are not limiting in their design.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The large-break LOCA event with a loss of offsite power and a single failure (disabling one ECCS train) establishes the OPERABILITY requirements for the ECCS. During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod assembly insertion for small breaks. Following depressurization, emergency cooling water is injected into the reactor vessel core flood nozzles, then flows into the downcomer, fills the lower plenum, and refloods the core.

The LCO ensures that an ECCS train will deliver sufficient water to match decay heat boiloff rates soon enough to minimize core uncovery for a large-break LOCA. It also ensures that the HPI pump will deliver sufficient water for a small-break LOCA and provide sufficient boron to maintain the core subcriticality.

In the LOCA analyses, HPI and LPI are not credited until 35 seconds after actuation of the ESFAS signal. This is based on a loss of offsite power and the associated time delays in startup and loading of the emergency diesel generator (EDG). Further, LPI flow is not credited until RCS pressure drops below the pump's shutoff head. For a large-break LOCA, HPI is not credited at all.

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

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that at least one is available, assuming a single failure in the other train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of an HPI subsystem and an LPI subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon an ESFAS signal and manually transferring suction to the containment sump.

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BASES (continued)

LCO (continued)

During an event requiring ECCS actuation, a flow path is provided to ensure an abundant supply of water from the BWST to the RCS via the HPI and LPI pumps and their respective discharge flow paths to each of the four cold leg injection nozzles and the reactor vessel. In the long term, this flow path may be manually transferred to take its supply from the containment sump and to supply its flow to the RCS via two paths, as described in the Background section.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

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

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

APPLICABILITY

In MODES 1, 2, and 3, the ECCS train OPERABILITY requirements for the large-break LOCA are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The HPI pump performance is based on the small-break LOCA, which establishes the pump performance curve and has less dependence on power. The HPI pump performance requirements are based on a small-break LOCA. MODES 2 and 3 requirements are bounded by the MODE 1 analysis.

As indicated in the Note, LCO 3.0.4 and SR 3.0.4 are excepted for entry into MODE 3. This exception is required for plants with an LTOP System arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," requires that certain pumps be rendered inoperable at and below the LTOP System arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status. This Note provides the needed time to restore the pumps and ensures

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BASES (continued)

APPLICABILITY (continued)

that they will be restored in a timely manner by imposing a time and temperature limit on the actions.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal and Coolant Circulation—High Water Level," and LCO 3.9.6, "Residual Heat Removal and Coolant Circulation—Low Water Level."

ACTIONS

A.1

With one or more components inoperable and at least 100% of the safety injection (SI) flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72-hour Completion Time is based on NRC recommendations (Ref. 4) that are based on a risk evaluation and is a reasonable time for many repairs.

An ECCS flow path is inoperable if it is not capable of delivering the design flow to the RCS. The individual components are inoperable if they are not capable of performing their design function or if supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the SI flow equivalent to 100% of a single train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

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BASES (continued)

ACTIONS (continued)

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown the risk of having one full ECCS train inoperable to be sufficiently low to justify continued operation for 72 hours.

The Completion Time of Required Action A.1 has been provided with a Note to clarify that all ECCS components for this LCO are treated as an entity with a single Completion Time, i.e., the Completion Time is on a Condition basis.

[For this facility, acceptable and unacceptable combinations of out-of-service components are established as follows:]

Reference 5 describes situations in which one component, such as a residual heat removal (RHR) crossover valve, can disable both ECCS trains. With one or more components inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable components cannot be returned to OPERABLE status within the associated Completion Times, 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 6 hours and at least MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power or by key locking the control in the correct position ensures that the valves cannot change position as the result

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

of an active failure. These valves are of the type described in Reference 5, which can disable the function of both ECCS trains and invalidate the accident analyses. A 12-hour Frequency is considered reasonable in view of other administrative controls that will ensure that a mispositioned valve is an unlikely possibility.

SR 3.5.2.2

Verifying the correct alignment for manual, power-operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. This surveillance 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 derived from inservice testing requirements for performing valve testing at least once every 92 days. The Frequency is further justified in view of the procedural control governing valve operation and to provide added assurance of correct valve positions.

SR 3.5.2.3

With the exception of systems in operation, the ECCS pumps are normally in a standby, non-operating mode. As such, the flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the piping from the ECCS pumps to the RCS full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent water hammer, pump cavitation, and pumping of non-condensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an ESFAS signal or during shutdown cooling. The 31-day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the existence of procedural controls governing system operation.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Flow and differential head are normal tests of centrifugal pump performance required by Section XI of the American Society of Mechanical Engineers (ASME) Code. Because RCS pressure is higher than the discharge head of the HPI and LPI pumps, they are tested on recirculation flow. Delivering their minimum recirculation flow, the pumps operate near their shutoff head. This test thus confirms one point on their design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. This testing also includes those valves in the LPI flow paths that are opened in long-term cooling to prevent boric acid in the reactor core region from reaching an unacceptably high concentration. A quarterly Frequency for such tests is a Code requirement.

SR 3.5.2.5 and SR 3.5.2.6

These SRs demonstrate that each automatic ECCS valve actuates to its required position on an actual or simulated ESFAS signal and that each ECCS pump starts on receipt of an actual or simulated ESFAS signal. The 18-month Frequency was developed considering the plant conditions needed to perform the SRs and the potential for unplanned plant transients if the SRs are performed with the reactor at power. The 18-month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the ESFAS testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.7

This surveillance ensures that these valves are in the proper position to prevent the HPI pump from exceeding its runout limit. This 18-month Frequency is based on the same reasons as those stated for SR 3.5.2.5 and SR 3.5.2.6.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.8

This surveillance ensures that the flow controllers for the LPI throttle valves will automatically contro` the LPI train flow rate in the desired range and prevent LPI pump runout as RCS pressure decreases after a LOCA. The 18-month Frequency is based on the same reasons as those stated for SR 3.5.2.5 and SR 3.'.2.6.

SR 3.5.2.9

Periodic inspections of the containment sump ensure that it is unrestricted and stays in proper operating condition. An "at refueling" Frequency is sufficient to detect abnormal degradation and is confirmed by operating experience.

SR 3.5.2.10

A source of fission-product leakage during a LOCA can be leakage from the ESF Systems external to containment during the recirculation phase of core cooling. Verifying the total leak rate for the two trains of the LPI System (SR [3.5.2.10]) and the two trains of the Containment Spray System (SR 3.6.6.8) does not exceed 0.57 gallons per hour at normal operating pressures during sump recirculation operation or at equivalent hydrostatic pressures provides assurance that the leak rates assumed for the systems during the recirculation phase of operation will not be exceeded. Therefore, assurance is provided that the resultant doses documented in the safety analysis will not be exceeded. The Frequency of this periodic surveillance (18 months) is based on the same reasons as those stated for SR 3.5.2.5 and SR 3.5.2.6.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 35, "Emergency Core Cooling System."
2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants."

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BASES (continued)

REFERENCES (continued)

3. [Unit Name] FSAR, Section [ ], "Emergency Core Cooling System."

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

5. IE Information Notice 87-01, "RHR Valve Misalignment Causes Degradation of ECCS in PWRs," January 6, 1987.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS—Shutdown

BASES

BACKGROUND

The Background section for Bases B 3.5.2 is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: high pressure injection (HPI) and low pressure injection (LPI), each consisting of two redundant, 100% capacity trains.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps, such that water from the borated water storage tank (BWST) can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 is applicable to these Bases.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. Included in these reductions is that automatic Engineered Safety Feature Actuation System (ESFAS) actuation is not available. Sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

An additional relaxation in the ECCS requirements for MODE 4 is that only one ECCS train is required. This requirement dictates that single failures are not considered during this MODE.

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to ensure sufficient ECCS flow is available to the core following a DBA.

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BASES (continued)

LCO (continued)

In MODE 4, an ECCS train consists of an HPI subsystem and an LPI subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the BWST to the RCS, via the ECCS pumps and their respective supply headers, to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS hot and cold legs.

[For this facility, the following support systems are required to be OPERABLE to ensure ECCS LPI and HPI subsystem OPERABILITY:]

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

This LCO is modified by a Note which states that HPI actuation may be blocked in accordance with LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System." Under LCO 3.4.12, this requirement must be met within 15 minutes before decreasing RCS temperature to ≤[283]°F, in order to comply with the LTOP analysis. Operator action is then required to initiate HPI. In the event of a loss-of-coolant accident (LOCA) requiring HPI actuation, the time required for operator action has been shown to be acceptable by analysis.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for the ECCS are covered by LCO 3.5.2, "ECCS—Operating."

In MODE 4 with the RCS temperature below 280°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

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BASES (continued)

APPLICABILITY (continued)

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "DHR and Coolant Circulation—High Water Level," and LCO 3.9.5, "DHR and Coolant Circulation—Low Water Level."

ACTIONS

A.1

For this facility, an OPERABLE ECCS LPI subsystem consists of an LPI pump, heat exchanger, piping, instruments, and controls to ensure an OPERABLE flow path.

If no LPI subsystem train is OPERABLE, the unit is not prepared to respond to a LOCA or to continue cooldown using the LPI pumps and decay heat exchangers. The Completion Time of 15 minutes, which would restore at least one ECCS LPI subsystem to OPERABLE status, ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat must be removed by an LPI train operating with suction from the RCS. If no LPI train is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generator(s) (SG). The alternate means of heat removal must continue until the inoperable ECCS LPI subsystem can be restored to operation so that continuation of decay heat removal (DHR) is provided.

If both LPI pumps and heat exchangers are inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the LPI trains operating in the DHR mode. Therefore, the appropriate action is to initiate measures to restore one ECCS LPI subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

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BASES (continued)

ACTIONS (continued)

B.1

For this facility, an OPERABLE ECCS HPI subsystem consists of an HPI pump and flow path from the BWST. The subsystem includes all the necessary piping, instruments, and controls required to ensure an OPERABLE flow path.

If no ECCS HPI subsystem is OPERABLE, due to the inoperability of the HPI pump or flow path from the BWST, the plant is not prepared to provide high-pressure response to Design Basis Events requiring ESFAS. The 1-hour Completion Time to restore at least one ECCS HPI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

The Note associated with Required Action B.1 is intended to convey that continuation of actions is needed to restore the ECCS HPI subsystem to OPERABLE status, considering that the plant cannot go to MODE 5 because no DHR capability is available.

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators. The Note associated with Required Action A.1 is intended to restrict entry into this condition to only when at least one LPI subsystem is OPERABLE. The Note also is intended to convey the suspension of further action to reach MODE 5 if, while in Condition C, all LPI subsystems become inoperable. Should the plant be in Condition A, no LPI subsystems OPERABLE, it is not advisable or practical to go to MODE 5. In this situation, the SGs can be used to maintain MODE 4 until an LPI subsystem is restored to OPERABLE status. Should the plant be in Condition B only, an inoperable HPI subsystem, it is possible to reach MODE 5 by using an LPI subsystem.

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BASES (continued)

SURVEILLANCE REQUIREMENTS	The applicable surveillance descriptions from Bases 3.5 2 apply.
REFERENCES	The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Borated Water Storage Tank (BWST)

BASES

BACKGROUND

The BWST supports the ECCS and the Containment Spray System by providing a source of borated water for ECCS and containment spray pump operation. In addition, the BWST supplies borated water to the refueling pool for refueling operations.

The BWST supplies two ECCS trains, each by a separate, redundant supply header. Each header also supplies one train of the Containment Spray System. A normally open, motor-operated isolation valve is provided in each header to allow the operator to isolate the BWST from the ECCS after the ECCS pump suction has been transferred to the containment sump following depletion of the BWST during a loss-of-coolant accident (LOCA). Use of a single BWST to supply both ECCS trains is acceptable because the BWST is a passive component and passive failures are not assumed in the analysis of Design Basis Events (DBEs) to occur coincidentally with the Design Basis Accident (DBA).

The ECCS and containment spray pumps are provided with recirculation lines that ensure that each pump can maintain minimum flow requirements when operating at shutoff head conditions. These lines discharge back to the BWST, which is vented to the atmosphere. When the suction for the ECCS and containment spray pumps is transferred to the containment sump, this flow path must be isolated to prevent a release of the containment sump contents to the BWST. If not isolated, this could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the pumps.

This LCO ensures that the BWST contains sufficient borated water to support the ECCS during the injection phase, ensures that a sufficient water volume exists in the containment sump to support continued operation of the ECCS and containment spray pumps at the time of transfer to the recirculation mode of cooling, and ensures that the reactor remains subcritical following a LOCA. Insufficient water inventory in the BWST could result in insufficient cooling capacity of the ECCS when the transfer to the recirculation mode occurs.

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BACKGROUND (continued)

Improper boron concentrations could result in a loss of SHUTDOWN MARGIN or excessive boric acid precipitation in the core following a LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the BWST provides a source of borated water to the high pressure injection (HPI), low pressure injection (LPI), and containment spray pumps. As such, it provides core cooling and replacement inventory, containment cooling and depressurization, and is a source of negative reactivity for reactor shutdown. The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of Specifications B 3.5.2, "ECCS—Operating," and B 3.6.5, "Containment Spray and Cooling Systems." Reference to these analyses is used to assess changes to the BWST in order to evaluate their effects in relation to the acceptance limits.

The limit on volume of [≥ 415,200 gallons and ≤ 449,000 gallons] is based on several factors. Sufficient deliverable volume must be available to provide at least 20 minutes of full flow of all ECCS pumps prior to the transfer to the containment sump for recirculation. Twenty minutes gives the operator adequate time to prepare for switchover to containment sump recirculation.

A second factor that affects the minimum required BWST volume is the ability to support continued ECCS pump operation after the manual transfer to recirculation occurs. When ECCS pump suction is transferred to the sump, there must be sufficient water in the sump to ensure adequate net positive suction head (NPSH) for the LPI and containment spray pumps. This NPSH calculation is described in the FSAR (Ref. 1), and the amount of water that enters the sump from the BWST and other sources is one of the input assumptions. Since the BWST is the main source that contributes to the amount of water in the sump following a LOCA, the calculation must not take credit for more than the minimum volume of usable water from the BWST.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The third factor is that the volume of water in the BWST must be within a range that will ensure that the solution in the sump following a LOCA is within a specified pH range that will minimize the evolution of iodine and the effect of chloride and caustic stress corrosion cracking on the mechanical systems and components.

The volume range ensures that refueling requirements are met and that the capacity of the BWST is not exceeded. Note that the volume limits refer to total, rather than usable, volume required to be in the BWST; a certain amount of water is unusable because of tank discharge line location or other physical characteristics.

The [2270] ppm limit for minimum boron concentration was established to ensure that, following a LOCA with a minimum BWST level, the reactor will remain subcritical in the cold condition following mixing of the BWST and Reactor Coolant System (RCS) water volumes. Large-break LOCAs assume that all control rods remain withdrawn from the core.

The minimum and maximum concentration limits both ensure that the solution in the sump following a LOCA is within a specified pH range that will minimize the evolution of iodine and the effect of chloride and caustic stress corrosion cracking on the mechanical systems and components.

The [2450] ppm maximum limit for boron concentration in the BWST also is based on the potential for boron precipitation in the core during the long-term cooling period following a LOCA. For a cold leg break, the core dissipates heat by pool nucleate boiling. Because of this boiling phenomenon in the core, the boric acid concentration will increase in this region. If allowed to proceed in this manner, a point may be reached where boron precipitation will occur in the core. Post-LOCA emergency procedures direct the operator to establish dilution flow paths in the LPI System to prevent this condition by establishing a forced flow path through the core regardless of break location. These procedures are based on the minimum time in which precipitation could occur, assuming that maximum boron concentrations exist in the borated water sources used for injection following a LOCA.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	Boron concentrations in the BWST in excess of the limit could result in precipitation earlier than assumed in the analysis. The [40]°F lower limit on the temperature of the solution in the BWST was established to ensure that the solution will not freeze. This temperature also helps prevent boron precipitation and ensures that water injection in the reactor vessel will not be colder than the lowest temperature assumed in reactor vessel stress analysis. The [100]°F upper limit on the temperature of the BWST contents is consistent with the maximum injection water temperature assumed in the LOCA analysis. The numerical values of the parameters stated in the SR are actual values and do not include allowance for instrument errors. The BWST satisfies Criterion 3 of the NRC Interim Policy Statement.
LCO	The BWST exists to ensure that an adequate supply of borated water is available to cool and depressurize the containment in the event of a DBA; to cool and cover the core in the event of a LOCA, thereby ensuring the reactor remains subcritical following a DBA; and to ensure adequate level exists in the containment sump to support ECCS and containment spray pump operation in the recirculation MODE. To be considered OPERABLE, the BWST must meet the limits established in SRs for volume, boron concentration, and temperature. [For this facility, the following support systems are required to be OPERABLE to ensure BWST OPERABILITY:] [For this facility, those required support system which, upon their failure, do not require declaring the BWST inoperable and their justification are as follows:]
APPLICABILITY	In MODES 1, 2, 3, and 4, the BWST OPERABILITY requirements are dictated by the ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and

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BASES (continued)

APPLICABILITY (continued)

Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the BWST must be OPERABLE to support their operation.

Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops—MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops—MODE 5, Loops Not Filled," respectively. MODE 6 core cooling requirements are addressed by LCO 3.9.4, "DHR and Coolant Circulation—High Water Level," and LCO 3.9.5, "DHR and Coolant Circulation—Low Water Level."

ACTIONS

A.1

If the BWST borated water volume, boron concentration, or borated water temperature is not within limits, the BWST must be returned to within limits within 1 hour. In this condition, neither the ECCS nor the Containment Spray System can perform its design functions. Under these conditions, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the BWST is not required. The short period of 1-hour to restore the BWST to OPERABLE is based on this condition simultaneously affecting multiple trains.

If the equipment used to verify BWST borated water volume, concentration, or temperature is determined to be inoperable, the BWST is considered to be not within limits and Required Action A.1 applies to restore such equipment to OPERABLE status.

B.1 and B.2

If the BWST cannot be returned 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 6 hours and in MODE 5 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 without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

Verification every 24 hours that the BWST water temperature is within the specified temperature band ensures that the boron will not precipitate, the fluid will not freeze, the fluid temperature entering the reactor vessel will not be colder than assumed in the reactor vessel stress analysis, and the fluid temperature entering the reactor vessel will not be hotter than assumed in the LOCA analysis. The 24-hour Frequency is short enough to identify a temperature change that would approach either temperature limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that requires the surveillance to be performed only when the ambient air temperatures are outside the operating temperature limits of the BWST. With ambient temperatures within this band, the BWST temperature should not exceed the limits.

[For this facility, BWST borated water temperature is measured as follows:]

SR 3.5.4.2

Verification every 7 days that the BWST contained volume is maintained within the required range ensures that a sufficient initial supply is available for injection and to support continued ECCS pump operation on recirculation. Since the BWST volume is normally stable and provided with a low level alarm, a 7-day Frequency has been proven to be appropriate through operating experience.

[For this facility, BWST borated water volume is measured as follows:]

SR 3.5.4.3

Verification every 7 days that the boron concentration of the BWST fluid is maintained within the required band ensures that the reactor will remain subcritical following a LOCA. Since the BWST volume is normally stable, a 7-day sampling Frequency is appropriate and has been shown to be acceptable through operating experience.

[For this facility, BWST boron concentration is measured as follows:]

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BASES (continued)

REFERENCES 1. [Unit Name] FSAR, Section [b], "[Title]," and Section [15], "[Title]."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment is comprised of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed 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). Additionally, this structure provides biological shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a shallow dome roof. For containments with ungrouted tendons, the cylinder wall is prestressed with a post-tensioning system in the vertical and horizontal directions, and the dome roof is prestressed using a three-way post-tensioning system. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete reactor building is required for structural integrity of the containment under DBA conditions. The steel liner and its penetrations establish the leakage-limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission-product radioactivity from the containment to the environment. Loss of containment OPERABILITY could cause site-boundary doses, in the event of a DBA, to exceed values given in the licensing basis. 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 containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage

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(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

rate, so that, in conjunction with the other containment systems and ENGINEERED SAFETY FEATURE 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 DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss-of-coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 3). In addition, release of significant fission-product radioactivity within containment can occur from a LOCA or a REA. In the DBA analyses, it is assumed that the containment is OPERABLE at event initiation such that, for the DBAs involving release of fission-product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of [0.25]% of containment air weight per day (Ref. 4). This leakage rate, used in the evaluation of offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J (Ref. 2), as L_a: the maximum allowable leakage rate at the calculated maximum peak containment pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. For this unit, L_a = [0.25]% per day and P_a = [53.9] psig, resulting from the limiting design basis LOCA (Ref. 4).

Satisfactory leakage-rate test results are a requirement for the establishment of containment OPERABILITY. 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.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

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.

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

LCO

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

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

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;

c. Each airlock is OPERABLE (see LCO 3.6.2, Condition C, Note 1);

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

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

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(continued)

BASES (continued)

LCO (continued)

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

The Required Actions when other containment LCOs are not met have been specified in those LCOs and not in LCO 3.6.1.

Compliance with LCO 3.6.1 will ensure a containment configuration that is structurally sound and will limit leakage to those leakage rates assumed in the safety analysis. 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 are implemented as follows:

a. The OPERABILITY of valves that are closed or are required to close in response to a containment isolation signal is ensured by SR 3.6.3.4, SR 3.6.3.5, SR 3.6.3.6, and SR 3.6.3.7 of LCO 3.6.3, "Containment Isolation Valves." 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 4. The SRs require that the associated containment isolation valves close within the required time limit, that the affected penetration is isolated by closed isolation valves or blind flanges, or the plant is shut down. In addition, the Type C test required by SR 3.6.3.7 and Appendix J requires that these containment isolation valves 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.

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

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BASES (continued)

LCO (continued)

c. The OPERABILITY of containment air locks is assured by conformance with LCO 3.6.2, "Containment Air Locks," which requires that at least one door in each air lock be closed during MODES 1, 2, 3, and 4; that the air locks satisfy the required 10 CFR 50, Appendix J (Ref. 2), leakage-test requirements, as described in the containment Leakage Rate Testing Program; and that the door interlocks function as required;

d. The containment leakage-rate requirements conform with those of 10 CFR 50, Appendix J (Ref. 2), and the Containment Leakage Rate Testing Program. These requirements are implemented to ensure that the reactor containment, as a whole, and each of its penetrations and isolation valves do not exceed the specified leakage rates; and

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, in MODE 5, containment is not required to be OPERABLE to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

(continued)

BASES (continued)

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1-hour Completion Time for correcting the problem is commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures the probability of an accident (requiring containment OPERABILITY) occurring during periods where containment is inoperable is minimal.

B.1 and B.2

If 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 6 hours and in MODE 5 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 3.6.1.1

Maintaining the 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 as described in the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to overall containment leakage (Type A Leakage Tests), leakage from equipment hatch, electrical penetrations, and other penetrations except air locks (Type B Leakage Tests), and containment isolation valves except [42]-inch purge valves (Type C Leakage Tests). Leakage rate testing of the containment purge valves is addressed in LCO 3.6.3, "Containment Isolation Valves." Air-lock door-seal leakage testing is addressed in LCO 3.6.2, "Containment Air Locks." SR Frequencies are as required by Appendix J or identified in the Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows SR Frequency extensions) does not apply.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analyses.

SR 3.6.1.2

For containment with ungrouted, post-tensioned tendons, this surveillance ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 5).

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 [ ], "[Accident Analysis]."

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

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

3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 feet in diameter, with a door at both ends. The doors are interlocked to prevent simultaneous opening. During periods when 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 containment entry is necessary. Each air-lock door has been designed and is tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in Containment. As such, closure of a single door supports 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 containment internal pressure results in increased sealing force on each door).

Each personnel air-lock door is provided with limit switches 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.

The containment air locks form part of the 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 are in conformance with 10 CFR 50, Appendix J (Ref. 1), as modified by approved exemptions.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The containment air lock LCO is derived from the requirements related to the control of offsite radiation doses from major accidents by verifying that the actual containment leakage rate does not exceed the value assumed in the plant safety analysis. For example, the loss-of-coolant accident (LOCA) analysis requires the containment boundary to ensure that the site boundary radiation dose will not exceed the limits of 10 CFR 100, or the NRC staff-approved plant-specific licensing basis (e.g., 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 containment.

The DBAs that result in a release of radioactive material within containment are a LOCA, a steam line break, and a rod ejection accident (Ref. 3). In the analysis of each of these accidents, it is assumed that containment is OPERABLE at event initiation, such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable Leakage rate of [0.25]% of containment air weight per day (Ref. 4). 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 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 public who remains at the low-population-zone boundary for the duration of the accident.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

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.

Closure of single door in each air lock is sufficient to support 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 containment.

The containment air locks satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

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

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

This LCO provides assurance that the containment air locks will perform their designed safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the Reference 2 limits or some fraction thereof, as established by the NRC staff-approved licensing basis.

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BASES (continued)

LCO (continued)

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

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

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 refueling operations are addressed in LCO 3.9.4, "Containment Building Penetrations."

The Required Actions for Conditions A, B, and 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 containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit the OPERABLE door must be immediately closed. If as low as reasonably achievable conditions permit, entry and exit should be via an OPERABLE air lock.

An additional Note has been included to provide clarification that all containment air locks are 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 in one or more containment air locks, the OPERABLE door must be verified closed and must remain closed in each affected containment air lock.

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BASES (continued)

ACTIONS (continued)

This assures a leak-tight containment barrier is maintained by the use of an OPERABLE air-lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires containment be restored to OPERABLE status within 1 hour.

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

Required Action A.2.2.2 verifies that an air lock with an inoperable door has been isclated by the use of a locked and closed OPERABLE air-lock door. This ensures that an acceptable containment leakage boundary is maintained. The leakage-rate acceptance criteria are as defined in SR 3.6.2.1. The periodic interval of 31 days is based on engineering judgment and is considered adequate in view of other administrative controls, such as door status indications available to the operator that ensure that the OPERABLE air-lock door remains closed.

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

With an air-lock door interlock mechanism inoperable in one or more air locks, 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 a time and to ensure that the opened door is immediately closed.

C.1 and C.2

With one or more air lock(s) inoperable for reasons other than those described in Conditions A or B, one door in the

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BASES (continued)

ACTIONS (continued)

containment air lock must be verified to be closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air locks(s) must be restored to OPERABLE status within the 24-hour Completion Time. The specified time period is considered reasonable for restoring inoperable air locks to OPERABLE status assuming that at least one door is maintained closed in each affected air lock.

The Required Actions of Condition C are modified by a Note that requires the containment to be declared inoperable should both doors in an air lock fail the air-lock door-seal test, SR 3.6.2.1.

D.1 and D.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable containment air lock cannot be restored to OPERABLE status within the associated Completion Times. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 5 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 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage-rate test requirements of 10 CFR 50, Appendix J (Ref. 1), as modified by approved exemptions [and as described in the Containment Leakage rate Testing Program]. This SR reflects the leakage-rate testing requirements with regard to air-lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing and in accordance with 10 CFR 50, Appendix J, are stated in this SR. The periodic testing requirements verify that the air-lock leakage does not exceed the allowed fraction of the

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

overall containment leakage rate. The Surveillance Frequency is required by Appendix J, as modified by approved exemptions, and is described in the Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows Surveillance Frequency extensions) does not apply.

The SR has been modified by a Note to indicate 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 3.6.2.2

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

REFERENCES

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

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BASES (continued)

REFERENCES (continued)

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 [ ], "[Accident Analysis]."

4. [Unit Name] FSAR, Section [ ], "[Accident Analysis]."

DRAFT

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident-consequence-limiting systems to be provided with two isolation barriers that are closed on an automatic isolation signal. These isolation devices consist of either passive devices or active (automatic) devices. 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 10 CFR 50, Appendix A, GDC 57 (Ref. 1). Check valves, or other automatic valves designed to close following an accident without operator 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 containment OPERABILITY) or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system inside containment (in accordance with the requirements of 10 CFR 50, Appendix A, GDC 57). These barriers (typically containment isolation valves) make up the containment isolation system.

Containment isolation occurs upon receipt of a high containment pressure or diverse containment isolation signal. The containment isolation signal closes automatic containment isolation valves in fluid penetrations not required for operation of engineered safeguards systems to prevent leakage of radioactive material. Upon actuation of high-pressure injection, automatic containment valves also isolate systems not required for containment or Reactor Coolant System (RCS) heat removal. Other penetrations are isolated by the use of valves in the closed position or blind flanges. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated in the event of a release of radioactive material to containment atmosphere from the RCS following a Design Basis Accident (DBA).

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BASES (continued)

BACKGROUND (continued)

OPERABILITY of the containment isolation valves (and blind flanges) ensures containment OPERABILITY is maintained during accident conditions.

The OPERABILITY requirements for containment isolation valves help ensure that adequate 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 containment leakage rates assumed in the safety analyses will not be exceeded.

The reactor building purge system is part of the reactor building ventilation system. The purge system was designed for intermittent operation, providing a means of removing airborne radioactivity caused by minor leakage from the reactor coolant system prior to personnel entry into containment. The containment purge system consists of one [48]-inch line for exhaust and one [48]-inch line for supply, with supply and exhaust fans capable of purging the containment atmosphere at a rate of approximately [50,000] ft^3/min. This flow rate is sufficient to reduce the airborne radioactivity level within containment to levels defined in 10 CFR 20 (Ref. 2) for a 40-hour work week within 2 hours of purge initiation during reactor operation. The containment purge supply and exhaust lines each contain two isolation valves that receive an isolation signal on high containment radiation [and high containment pressure].

Failure of the purge valves to close following such an event would cause a significant increase in the offsite radiation dose because of the large containment leakage path introduced by these [48]-inch purge lines. Failure of the purge valves to close would result in leakage considerably in excess of the containment design leakage rate of [0.25]% of containment air weight per day (Ref. 3). Because of their large size, the [48]-inch purge valves in some plants are not qualified for automatic closure from their open position under DBA conditions. Therefore, the [48]-inch purge valves are normally maintained sealed-closed (SR 3.6.3.1) in MODES 1 through 4 to ensure leak tightness.

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BASES (continued)

BACKGROUND (continued)

The containment minipurge valves operate to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access; and

b. Equalize internal and external pressures.

Since the minipurge valves are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1 through 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the requirements related to the control of offsite radiation doses resulting from major accidents. As delineated in 10 CFR Part 100 (Ref. 4), the determination of exclusion areas and low population zones surrounding a proposed site must consider a fission-product release from the core with offsite release based on the expected demonstrable leakage rate from the containment. This LCO is intended to ensure that the offsite dose limits are not exceeded (actual containment leakage rate does not exceed the value assumed in the safety analyses). As part of the containment boundary, containment isolation valve and containment purge valve OPERABILITY are essential to containment OPERABILITY. Therefore, the safety analysis of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss-of-coolant accident (LOCA) or a rod ejection accident (Ref. 5). In the analysis for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential leakage paths to the environment through containment isolation valves (including containment purge valves) are minimized. The offsite dose calculations assumed that the [48]-inch purge valves were closed at event initiation. Likewise, it is assumed that the containment is isolated such that release of fission products to the environment is controlled by the rate of containment leakage.

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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 the 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 Reference 4 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 DBA analysis assumes that, within 60 seconds of the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve 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 containment purge valves. Two valves in a 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 purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed-closed during MODES 1, 2, 3, and 4. In this case, the single-failure criterion remains applicable to the containment purge valve because of failure in the control circuit associated with each valve. Again, the purge system valve design prevents a single failure from

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

compromising containment OPERABILITY as long as the system is operated in accordance with the subject LCO.

The containment isolation valves and containment purge valves satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valve safety function is related to control of offsite radiation exposures resulting from a DBA. This LCO addresses containment isolation valve OPERABILITY and containment purge valve leakage. Other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," under Type C testing.

The automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The containment purge valves have different OPERABILITY requirements. The [48]-inch purge valves must be maintained sealed-closed, and purge valves with resilient seals must meet additional leakage-rate requirements (SR 3.6.3.7). Also, purge system valves actuate on an automatic isolation signal. The valves covered by this LCO are listed along with their associated stroke times in the FSAR (Ref. 6).

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. 1). These passive isolation valves/devices are those listed in Reference 7.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designated safety functions to mitigate the consequences of accidents that could result in offsite exposure comparable to the Reference 4 limits, or some fraction as established in the NRC staff-approved licensing basis.

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(continued)

BASES (continued)

LCO (continued)

[For this facility, the following support systems are required OPERABLE to ensure containment isolation valve OPERABILITY:]

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE and the containment purge valves are not required to be sealed-closed in MODE 5. The requirements for containment isolation valves and containment purge valves during MODE 6 refueling operations are addressed in LCO 3.9.3, "Containment Building Penetrations."

The Applicability is modified by a Note allowing normally locked- or sealed-closed containment isolation valves, except the [48]-inch purge valves, to be opened intermittently under administrative control. These administrative controls consist of stationing at the valve controls a dedicated operator who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a valid containment isolation signal is indicated. Due to the size of the 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.

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.

(continued)

BASES (continued)

ACTIONS

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

With one or more containment isolation valves 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 if the valve is out of service for maintenance or other reasons. This Required Action is to be completed within 1 hour to provide assurance that a containment penetration can be isolated when required to prevent a loss of containment OPERABILITY. The associated Completion Time is consistent with LCO 3.6.1, "Containment," and is considered a reasonable length of time needed to complete the Required Action.

In the event one or more containment isolation valves 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 containment isolation valve, a closed manual valve, a blind flange, or a check valve inside 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 one to 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 the relative importance of maintaining containment OPERABILITY during MODES 1, 2, 3, and 4.

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 penetrations must be verified to be isolated on a periodic basis. This periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time for this Required Action is once every 31 days for valves

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(continued)

BASES (continued)

ACTIONS (continued)

outside containment; for valves inside containment, the Frequency is prior to entering MODE 4 from MODE 5 if not performed more often than once per 92 days. The Completion Time of once per 31 days was developed based upon Inservice Inspection and Testing Program requirements to perform valve testing at least once every 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 potentially capable of being mispositioned are in the correct position. For the valves inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 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 this Condition is not applicable to those penetrations with only one containment isolation valve and a closed system inside containment (i.e., the containment penetration is isolated in accordance with 10 CFR 50, Appendix A, GDC No. 57, Reference 1). The Required Actions for Condition A assume two valves in series are used to isolate the containment penetration and satisfy single-failure concerns.

Required Action A.1 has been modified by a Note stating that 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 inside containment, the Note to A.1 refers to penetrations with a single isolation valve on a system that is open inside containment but closed outside containment. For these systems, if the single isolation valve is inoperable, the intent is to go directly to A.2.1. These systems are very small piping lines, such as instrument lines, which are a closed system outside of 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.

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BASES (continued)

ACTIONS (continued)

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

With one or more containment isolation valves 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. 1) 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. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment OPERABILITY during MODES 1, 2, 3, and 4. In the event 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 periodic verification is necessary to ensure that containment OPERABILITY is maintained and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration is isolated is appropriate considering the fact that 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 those penetrations with only one containment isolation valve and a closed system inside 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. 1). GDC 57 allows lines that enter containment and are not part of the reactor coolant pressure boundary nor connected directly to containment atmosphere to be isolated by means of one containment isolation valve.

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

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage

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BASES (continued)

ACTIONS (continued)

must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and deactivated automatic valve, a closed manual valve, or blind flange. One of these Required Actions must be completed within the 24-hour Completion Time. The specified time period is reasonable, considering the fact the containment purge valves remain closed so that a gross breach of containment does not exist. For containment purge valves that are isolated in accordance with Required Action C.2.1, SR 3.6.3.7 must be performed at least once every 92 days. This ensures that degradation of the resilient seals is detected and confirms that the leakage rate of the containment purge valves does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.7, 184 days, is based on an NRC initiative, Generic Issue B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 8). Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen.

D.1

With one or more containment isolation valves inoperable in one or more penetration flow paths, verify tha[t th]e Required Actions have been initiated for those supported systems declared inoperable by the support containment isolation valves 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 containment isolation valves 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.]

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BASES (continued)

ACTIONS (continued)

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

E.1

With one or more containment isolation valves inoperable in one or more penetration flow paths, AND one or more required 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 situation, then LCO 3.0.3 may not need to be entered.

An example illustrating this situation would be when a support containment isolation valve is declared inoperable and subsequently is isolated in a penetration flow path associated with a supported ENGINEERED SAFETY FEATURE (ESF) subsystem, then the other penetration flow paths associated with the redundant counterpart supported ESF subsystems and their support subsystems 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 containment isolation valves.

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. This is done by placing the plant in at least MODE 3 within 6 hours and at least MODE 5 within 36 hours. Based on operating experience, the allowed Completion Times are reasonable 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 3.6.3.1

Each [48]-inch containment purge valve is required to be verified sealed-closed at 31-day intervals. This surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. 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. 4) or some fraction, as established in the NRC staff-approved licensing basis. Therefore, these valves are required to be sealed-closed during MODES 1, 2, 3, and 4. A containment purge valve that is sealed-closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The Surveillance interval is a result of an NRC initiative, Generic Issue B-24, related to containment purge valve use during plant operations (Ref. 9).

SR 3.6.3.2

This SR ensures the [8]-inch purge valves 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 pressure control, as low as reasonably achievable (ALARA) and air quality considerations for personnel entry, and for Surveillance tests that require the valve to be open. The [8]-inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31-day Surveillance interval is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

SR 3.6.3.3

This SR verifies that all containment isolation manual valves and blind flanges that are located outside 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 containment boundary is within design limits. The Inservice

(continued)

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 containment that are potentially capable of being mispositioned are in the correct position. Since verification of valve position for valves outside containment is relatively easy, the 31-day Frequency was chosen to provide added assurance of 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 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, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low. A second Note has been added that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls. These administrative controls consist of stationing at the valve controls a dedicated operator who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a valid 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 3.6.3.4

This SR verifies that all containment isolation manual valves and blind flanges that are located inside 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 containment boundary is within design limits. For valves inside containment, the Frequency defined as "prior to entering MODE 4 from MODE 5 if not performed more often than once per 92 days" is appropriate, since these valves and flanges are operated under administrative controls and the probability of their misalignment is low.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

A Note that allows normally locked- or sealed-closed isolation valves to be opened intermittently under administrative controls has been added to this SR. The administrative controls consist of stationing at the valve controls a dedicated operator who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a valid 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 3.6.3.5

Demonstrating that the isolation time of each power-operated and automatic containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures 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 should not exceed 92 days.

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. The 18-month Frequency was developed based on the consideration that it is prudent for this SR to be performed only during a plant outage, since isolation of penetrations would eliminate cooling water flow and disrupt 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 3.6.3.7

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

of 10 CFR 50, Appendix J (Ref. 10), is required to ensure OPERABILITY. The individual purge valve leakage-rate limits for this unit are [ ]. 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 containment and the environment), a Frequency of once per 184 days was established as part of the NRC resolution of Generic Issue B-20, "Containment Leakage Due to Seal Deterioration," (Ref. 8).

Additionally, this SR must be performed within 92 days of opening the valve. Ninety-two days was chosen recognizing that cycling the valve could introduce additional seal degradation (greater than that occurring 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 the results to be evaluated against the acceptance criteria of SR 3.6.1.1. This ensures that excessive containment purge valve leakage is properly accounted for in determining the overall containment leakage rate to verify containment OPERABILITY.

REFERENCES

1. 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

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BASES (continued)

REFERENCES (continued)

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

2. Title 10, Code of Federal Regulations, Part 20, "Standards for Protection Against Radiation."

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

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

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

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

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

8. Generic Issue (GI) B-20, "Containment Leakage Due to Seal Deterioration."

9. Generic Issue (GI) B-24, "Containment Purge Valve Reliability."

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

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The 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). The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss-of-coolant accident (LOCA) or steam line break (SLB). These limits also prevent the Containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits, a loss of containment OPERABILITY may result in the event of a DBA. Loss of containment OPERABILITY could cause site-boundary doses to exceed values specified in the licensing basis.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment OPERABILITY, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst-case LOCA generates larger mass and energy release than the worst-case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 2). The initial pressure condition used in the containment analysis was [17.7] psia ([3.0] psig). This resulted in a maximum peak pressure from a LOCA of [53.9] psig. The LCO (continued)

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

limit of [3.0] psig ensures that, in the event of an accident, the design pressure of [55] psig for containment is not exceeded. In addition, the building was designed for an internal pressure equal to [3] psig above external pressure during a tornado. The containment was also designed for an internal pressure equal to [2.5] psig below external pressure, to withstand the resultant pressure drop from an accidental actuation of the Containment Spray System. The LCO limit of [-2.0] psig ensures that operation within the design limit of [-2.5] psig is maintained (Ref. 3).

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

LCO

Maintaining containment pressure less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System. With containment pressure maintained within the limits of this LCO, Containment OPERABILITY is ensured.

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within design basis limits is essential to ensuring containment OPERABILITY, the LCO is applicable

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BASES (continued)

APPLICABILITY (continued)

in MODES 1, 2, 3, and 4. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODES 5 or 6 to ensure containment OPERABILITY.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, containment pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the Containment analysis. The 1-hour Completion Time is consistent with the ACTIONS of LCO 3.6.., "Containment," which requires that containment be restored to OPERABLE status in 1 hour.

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

B.1 and B.2

If containment pressure cannot be restored 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 6 hours and in MODE 5 within 36 hours. Based on operating experience, the allowed Completion Times are reasonable to reach the required MODES from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that facility operation remains within the limits assumed in the containment analysis. The 12-hour Frequency of this SR was developed after taking into consideration operating experience related to trending of containment pressure variations and pressure instrument drift during the applicable MODES. Furthermore, the 12-hour Frequency is

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)	considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment 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]." 3. Title 10, Code of Federal Regulations, Part 50, Appendix K, "ECCS Evaluation Models."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material, which may be released from the reactor core following a Design Basis Accident (DBA), such that offsite radiation exposures are maintained within the guidelines of 10 CFR 100 (Ref. 1) or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss-of-coolant accident (LOCA) or steam line break (SLB). In addition, though equipment installed inside Containment is designed to operate at higher temperatures than allowed by this LCO, this temperature limit may help to minimize component degradation that may result from extended exposure to a high-temperature environment (Ref. 2).

The containment average air-temperature limit is derived from the input conditions functional analyses and the containment structure external pressure. This LCO ensures that initial conditions assumed in the analysis of a DBA are not violated during plant operations. The total amount of energy to be removed from the Containment Cooling System during post-accident conditions is dependent upon the quality of energy released to the containment due to the event as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in a higher peak containment pressure and temperature. Exceeding Containment design pressure may result in leakage greater than that analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

air temperature ensures that operation is maintained within the DBA analysis assumptions for containment.

Several accidents (primarily LOCA and SLB) result in a marked increase in containment temperature and pressure due to energy release within the containment. Of these, the LOCA [illegible]ults in the greatest challenge to containment [illegible]. By maintaining containment air temperature at [illegible] the initial temperature assumed in the LOCA analysis, the reactor building (RB) design condition will not be exceeded.

The LOCA that was identified as presenting the greatest challenge to containment OPERABILITY was a cold-leg Reactor Coolant System break, of specified size, at a reactor coolant pump suction. In the original analysis of this event, the initial containment temperature and pressure were assumed to be [110°]F and [0] psig respectively. A re-evaluation of this event was later performed to determine the effect of increasing the initial RB temperature to [130°]F. The results of this re-evaluation indicated that a maximum containment air temperature of a specified value would be reached, providing an adequate margin to the containment design temperature. When an initial containment pressure of [3] psig (versus the original analysis assumption of [0] psig) was assumed, the event resulted in a maximum containment internal pressure that was less than the containment design pressure of [55] psig. Finally, an initial containment relative humidity of [90%] was evaluated for its effect on the above LOCA analysis. The resultant peak containment temperature, [ ]°F, must be postulated to be within the design temperature, [ ]°F. For this facility, the temperature limit used to establish the environmental qualification operating envelope for containment is [ ]°F.

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

LCO

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

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BASES (continued)

LCO (continued)

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODES 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 8-hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems or to prepare the plant for an orderly shutdown.

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

B.1 and B.2

If the containment average air temperature cannot be restored to within the limit 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 6 hours and in MODE 5 within 36 hours.

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(continued)

BASES (continued)

ACTIONS (continued)

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 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the containment analyses. In order to determine the average temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. The 24-hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). 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 containment temperature condition.

The required number of OPERABLE channels is established in LCO [ ] or SR [ ].

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 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

Containment Spray System

The Containment Spray System supports the containment OPERABILITY by furnishing containment atmosphere cooling to limit post-accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine-removal capability of the spray reduces the release of fission-product radioactivity from Containment to the environment, in the event of a Design Basis Accident (DBA), to less than the guidelines of 10 CFR 100 (Ref. 1), or the NRC staff-approved licensing basis (e.g., specified fraction of 10 CFR 100 limits). The Containment Spray System is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," and GDC 40, "Testing of Containment Heat Removal Systems," or other documents that were appropriate at the time of licensing (identified on a plant-specific basis).

The Containment Spray System consists of two separate trains, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ENGINEERED SAFETY FEATURE (ESF) bus. The borated water storage tank (BWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment Spray System pump suction is manually transferred from the BWST to the containment sump(s).

The Containment Spray System provides a spray of relatively cold borated water into the upper regions of containment to reduce the containment pressure and temperature during a DBA. In the recirculation mode of operation, heat is removed from the containment sump water by the decay-heat removal coolers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

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BASES (continued)

BACKGROUND (continued)

The Containment Spray System is actuated either automatically, by a containment High-High pressure signal coincident with a high-pressure injection signal, or manually. An automatic actuation opens the Containment Spray System pump discharge valves, and starts the two Containment Spray System pumps. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence.

Containment Cooling System

The Containment Cooling System is designed to furnish normal containment atmosphere cooling and limit post-accident pressure and temperature in containment to less than the design values. Reduction of containment pressure, in conjunction with the iodine-removal capability of the Containment Spray System, reduces the release of fission-product radioactivity from containment to the environment, in the event of a DBA, to less than that specified in the guidelines in the licensing basis.

The Containment Cooling System consists of three containment cooling units connected to a common duct suction header with four vertical return air ducts. Each cooling train is equipped with demisters, cooling coils, and an axial flow fan driven by a two-speed water-cooled electric motor. Each unit connection (two per unit) to the common header is provided with a backpressure damper for isolation purposes.

During normal operation, two containment cooling units are required to operate. The third unit is on standby and isolated from the operating units by means of the backpressure dampers. The swing unit is equipped with a transfer switch. It can be manually placed to either the "A" or "B" power train to operate in case one of the operating units fail. Upon receipt of an emergency signal, the two operating cooling fans running at high speed will automatically stop. The two cooling unit fans connected to the ESF buses will automatically restart and run at low speed, provided normal or emergency power is available.

In post-accident operation, following an actuation signal the Containment Cooling System fans are designed to start,

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BASES (continued)

BACKGROUND (continued)

automatically, in slow speed if they are not already running. If they are running at high (normal) speed, the running in high (normal) speed, the fans automatically stop. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere.

The Containment Cooling System and Containment Spray System are ESF systems. They are designed to ensure that the heat-removal capability required during the post-accident period can be attained. The Containment Spray System and Containment Cooling System provide containment redundant heat-removal operation. The Containment Spray System and Containment Cooling System provide redundant methods to limit and maintain post-accident conditions to less than the containment design values.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System ensure containment OPERABILITY by limiting the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered relative to Containment OPERABILITY are the loss-of-coolant accident (LOCA) and the steam line break. The postulated DBAs are analyzed, with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst-case single active failure, resulting in one train of the Containment Spray System and the Containment Cooling System inoperable.

The analysis and evaluation show that, under the worst-case scenario, the highest peak containment pressure is [53.9] psig (experienced during a LOCA). The analysis shows that the peak containment temperature is [276]°F (experienced during a LOCA). Both results are less than the design values. (See Bases B 3.6.4, "Containment Pressure," and B 3.6.5, "Containment Air Temperature," for a detailed discussion.) The analyses and evaluations assume a power level of [2568] MWt, one containment spray train and one containment cooling Train operating, and initial (pre-accident) conditions of [130]°F and [17.7] psia. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a [2.5] psig containment pressure drop and is associated with the sudden cooling effect in the interior of the air-tight containment. Additional discussion is provided in Bases B 3.6.4, "Containment Pressure."

The modeled Containment Spray System actuation from the containment analyses is based on a response time associated with exceeding the containment pressure High-High setpoint coincident with a high pressure injection signal to achieving full flow through the containment spray nozzles. The Containment Spray System total response time of [56] seconds includes diesel generator startup (for loss of offsite power), block loading of equipment, containment spray pump startup, and spray line filling (Ref. 2).

Containment cooling train performance for post-accident conditions is given in Reference 3. The result of the analysis is that each train can provide 33% of the required peak cooling capacity during the post-accident condition. The train post-accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 4.

The modeled Containment Cooling System actuation from the containment analysis is based on a response time associated with exceeding the containment pressure high setpoint to achieving full Containment Cooling System air and safety-grade cooling water flow. The Containment Cooling System total response time of [25] seconds includes signal delay, diesel generator startup (for loss of offsite power), and service water pump startup times (Ref. 5).

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of the NRC Interim Policy Statement.

LCO

During a DBA a minimum of one containment cooling train and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 6). Additionally, one containment spray train

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BASES (continued)

LCO (continued)

is required to remove iodine from the containment atmosphere and maintain offsite doses below guidelines of the licensing basis. To ensure that these requirements are met, two containment spray trains and two containment cooling units must be OPERABLE. Therefore, in the event of an accident, the minimum requirements are met, assuming the worst-case single active failure occurs.

Each Containment Spray System typically includes spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon an Engineered Safety Feature Actuation System signal and manually transferring suction to the containment sump.

Each Containment Cooling System typically includes demisters, cooling coils, dampers, an axial flow fan driven by a two-speed water-cooled electrical motor, instruments, and controls to ensure an OPERABLE flow path.

[For this facility, an OPERABLE Containment Spray System and an OPERABLE Containment Cooling System constitutes the following:]

[For this facility, the following support systems are required to ensure containment spray and cooling system OPERABILITY:

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

In addition, each Containment Spray System and Containment Cooling System must satisfy all the performance and physical arrangement requirements set forth by the SRs in order to be considered OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature, requiring the operation of the containment spray trains and containment cooling trains. In MODE 3 or MODE 4, individual plants may

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BASES (continued)

APPLICABILITY (continued)

justify removal of the Containment Spray System from operation to support Shutdown Cooling System operation. In this condition, the Containment Cooling System must remain OPERABLE. Justification of Containment Spray System removal will be addressed on a plant-specific basis. The probability and consequences of these events in MODES 5 and 6 are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and the Containment Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine-removal and containment cooling functions. The 72-hour Completion Time takes into account the redundant heat-removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply if the inoperable Containment Spray System cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 5 within 84 hours. The 6 hours allotted to reach MODE 3 is a reasonable time, based on operating experience, to shut down the plant from full power in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Containment Spray System in MODE 3, and 36 hours to reach MODE 5. This is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one of the required containment cooling trains inoperable, the inoperable containment cooling train must be

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BASES (continued)

ACTIONS (continued)

restored to OPERABLE status within 7 days. The components in this degraded condition are capable of providing greater than 100% of the heat-removal needs (for the condition with one containment cooling train inoperable) after an accident and provide iodine-removal capabilities. The 7-day Completion Time was developed taking into account the redundant heat-removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, and the low probability of a DBA occurring during this period.

D.1

With two of the required containment cooling trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. The components in this degraded condition provide iodine-removal capabilities and are capable of providing greater than 100% of the heat-removal needs after an accident. The 72-hour Completion Time was developed taking into account the redundant heat-removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, and the low probability of a DBA occurring during this period.

E.1

With two containment spray trains or any combination of three or more containment spray and containment cooling trains inoperable, the plant is in a Condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

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 for Condition C or D of this LCO are not met. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 5 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the Containment Spray System flow path provides assurance that the proper flow paths will exist for Containment Spray System 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. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment (only check valves are inside containment) capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

Operating each containment cooling train for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 31-day Frequency was developed considering the known reliability of the fan units and controls, the two-train redundancy available, and the low probability of a significant degradation of the containment cooling trains occurring between Surveillances, and has been shown to be acceptable through operating experience.

SR 3.6.6.3

Verifying a containment cooling train essential raw water cooling flow rate of ≥ [1780] gpm to each cooling unit provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 2). The 31-day Frequency of this SR was developed based on Inspection and Test Program requirements to perform testing on safety-related components at least once per 92 days. The Frequency

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

was also developed considering the known reliability of the cooling water system, the three-train redundancy available, and the low probability of a significant degradation of flow occurring between Surveillances.

SR 3.6.6.4

Demonstrating that each containment spray pump develops ≥ [250] psid differential pressure on recirculation ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 7). Since the Containment Spray System pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY and 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.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require a demonstration that each automatic containment spray valve actuates to its correct position and each containment spray pump starts on receipt of an actual or simulated actuation signal. The 18-month Frequency was developed considering it is prudent that these 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.

The Surveillance of containment sump isolation valves is also required by SR 3.5.2.5. A single Surveillance may be used to satisfy both requirements.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.7

This SR requires a demonstration that each containment cooling unit actuates on receipt of an actual or simulated actuation signal. The 18-month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.5 and SR 3.6.6.6 above for further discussion on the basis for the 18-month Frequency.

SR 3.6.6.8

With the containment spray inlet valves closed and the spray header drained of any solution, low-pressure air or smoke can be blown through test connections. Performance of this Surveillance demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the Containment during an accident is not degraded. Due to the passive nature of the design of the nozzles, a test at the first refueling and then at a 10-year intervals is considered adequate to detect degradation in nozzle performance.

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]."
4. [Unit Name] and "[Document Title]."
5. [Unit Name] FSAR, Section [ ], "[Title]."
6. [Unit Name] FSAR, Section [ ], "[Title]."
7. ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," American Society of Mechanical Engineers, New York.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System, which assists in reducing the iodine fission-product inventory in the containment atmosphere. Reduction of the iodine fission-product inventory limits the site-boundary exposure resulting from a Design Basis Accident (DBA) to within the thyroid dose guidelines of 10 CFR 100 (Ref. 1), or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

The Containment Spray System and Spray Additive System perform no function during normal plant operations. In the event of an accident such as a loss-of-coolant accident (LOCA), however, the Containment Spray System will be automatically initiated upon a high containment pressure signal by the Engineered Safety Feature Actuation System.

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Sodium hydroxide (NaOH), because of its stability when exposed to radiation and elevated temperature, is the preferred spray additive.

The spray additive tank is designed and located to permit gravity draining into the Containment Spray System. Both Containment Spray System pumps initially take suction from the borated water storage tank (BWST) via two independent flow paths. The spray additive tank has a common header that splits and feeds each of the Containment Spray System suction lines. The system is designed to inject at a rate commensurate with the draining rate of the BWST so that all borated water injected is mixed with NaOH.

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BASES (continued)

BACKGROUND (continued)

The flow rate is proportioned to provide a spray solution with a pH between 7.2 and 11.0 (Ref. 2). This range of alkalinity was established to not only aid in removal of airborne iodine, but also to minimize the corrosion of mechanical system components that would occur if the acidic borated water were not buffered. The pH range also considers the environmental qualification of equipment in Containment that may be subjected to the spray.

The Spray Additive System reduces the iodine fission-product inventory in the containment atmosphere. Loss of the Spray Additive System could cause site boundary radiation exposures resulting from a DBA to exceed the dose guidelines in the licensing basis.

APPLICABLE SAFETY ANALYSES

The containment Spray Additive System is essential to the effective removal of airborne iodine within containment following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value of [0.25]% air weight per day following the accident. The analysis assumes that most of the containment volume is covered by the spray.

The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System and is discussed in the Bases for Specification 3.6.6, "Containment Spray and Cooling Systems."

The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the entire spray additive tank volume is added to the remaining Containment Spray System flow path.

In the evaluation of the worst-case LOCA, the safety analysis assumed that an alkaline Containment spray effectively reduced the airborne iodine, minimizing the amount of activity available for release through containment leakage (Ref. 2). Thus, OPERABILITY of the Spray Additive System is essential to maintaining post-accident offsite

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

radiation doses within the guidelines of 10 CFR 100, or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

Each Containment Spray System suction line is equipped with its own gravity feed from the spray additive tank. Therefore, in the event of a single failure within the Spray Additive System (i.e., suction valve failure), NaOH will still be mixed with the borated water, establishing the alkalinity essential to effective iodine removal.

The Spray Additive System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow until the Containment Spray System suction path is switched from the BWST to the containment sump, and to raise the average spray solution pH to a level conducive to iodine removal. For this facility, the average spray solution pH is between [ ]. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned, and that automatic valves are capable of activating to their correct positions.

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

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

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BASES (continued)

LCO (continued)

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

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the operation of the Spray Additive System. The OPERABILITY of the Spray Additive System is essential to limiting the post-accident release of radioactive material to the environment within the limits specified in the licensing basis.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With the containment Spray Additive System inoperable, the system must be restored to OPERABLE status within 72 hours. The inoperability of the Containment Spray Additive System includes the loss of capability to inject NaOH to either Containment Spray System suction line or to both lines. The pH adjustment of the Containment Spray System for corrosion protection and iodine-removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 72-hour Completion Time takes into account the capability of the Containment Spray System to accept gravity feed from the Spray Additive System, reasonable time for repairs, and low probability of the worst-case DBA occurring during this period.

B.1 and B.2

The plant must be placed in a MODE in which the LCO does not apply in the event the Spray Additive System is not restored to OPERABLE status within the associated Completion Time. This is accomplished by placing the plant in at least MODE 3

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BASES (continued)

ACTIONS (continued)

within 6 hours, and in MODE 5 within 84 hours. The 6 hours allotted to reach MODE 3 is a reasonable time, based on operating experience, to shut down the plant from full power in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for restoration of the Spray Additive System and is reasonable when considering that the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of spray additive manual, power-operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. 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 also does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment capable of potentially being mispositioned are in the correct position.

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the BWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The 184-day Frequency is based on the low probability of an undetected change in tank volume occurring

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

during the SR interval (the tank is isolated during normal plant operations). Tank level is also indicated and alarmed in the control room, such that there is a high confidence that a substantial change in level would be detected.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The concentration of NaOH in the spray additive tank must be determined by chemical analysis. The 184-day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SR 3.6.7.4

This SR demonstrates that each automatic valve in the Spray Additive System flow path actuates to its correct position. The 18-month Frequency is sufficient to ensure valve OPERABILITY and was developed based on consideration that it is prudent to perform this Surveillance only during a plant outage. This is due to the plant conditions needed to perform the Surveillance. Operating experience has shown that these components usually pass the Surveillance when performed on the 18-month Frequency. Therefore the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.7.5

To ensure that the correct pH level is established in the borated water solution provided by the Containment Spray System, the flow rate in the Spray Additive System is demonstrated once per 5 years. This SR provides assurance that the correct amount of NaOH will be metered into the flow path upon Containment Spray System initiation. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow rate.

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BASES (continued)

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]."

DRAFT

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Monitors—MODES 1 & 2

BASES

BACKGROUND

Hydrogen monitors are required to monitor the hydrogen concentration in the containment following a loss-of-coolant accident (LOCA) or steam line break (SLB) in containment. Hydrogen may accumulate or pocket within containment following a LOCA as a result of a metal-steam reaction involving the zirconium fuel cladding and the reactor coolant, radiolytic decomposition of the post-accident emergency cooling solutions, corrosion of metals by solutions used for emergency cooling and containment spray, and hydrogen in the Reactor Coolant System (RCS) at the time of the LOCA. The primary source of hydrogen production after an SLB is corrosion of aluminum by caustic solutions (containment spray). The lower flammability limit of hydrogen is 4.1 volume percent (v/o) (Ref. 1). Should the lower flammability limit be exceeded, hydrogen ignition could occur. This could lead to overpressurization of containment, resulting in a breach of containment OPERABILITY, unacceptably high containment leakage and offsite doses, and damage to safety-related equipment inside containment.

The hydrogen monitors are post-accident Type C, Category 1, instruments. As such they will function to allow monitoring of hydrogen following a LOCA or SLB in containment.

Two independent hydrogen monitors have been provided, and each is powered from a separate vital AC power source. The monitors are manually actuated from their control panels and are required to operate after a LOCA. When actuated, the monitors will continuously monitor hydrogen concentration levels between 0% and 10%. Both monitors have the capability to analyze two areas that have been selected to provide a representative sample of the containment atmosphere following an accident.

The hydrogen monitors provide the capability to measure the hydrogen concentration in containment so that required operator actions (e.g., to actuate the hydrogen recombiners or Hydrogen Purge System in accordance with emergency procedures) may be taken to prevent the hydrogen

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BASES (continued)

BACKGROUND (continued)

concentration from exceeding the flammability limit of 4.1 v/o. Accurate measurement of hydrogen is attained at containment pressures up to 50 psi and temperatures up to 445°F (Ref. 2). The information provided by these analyzers is used by the plant operators to determine when Hydrogen Purge System or hydrogen recombiner actuation is required to maintain the hydrogen concentration below the lower flammability limit. This will eliminate the potential for a breach of containment due to a hydrogen-oxygen reaction.

APPLICABLE SAFETY ANALYSES

The hydrogen monitors monitor the post-accident containment atmosphere and provide an indication of containment hydrogen concentration. This information is utilized by the operators to determine when the combustible gas control systems (Hydrogen Purge System and hydrogen recombiners) should be actuated, if needed, to maintain the hydrogen concentration below the flammability limit.

Assumptions recommended in Reference 1 are used to maximize the amount of hydrogen calculated. The calculations confirm that when mitigating systems are actuated, in accordance with the emergency procedures, the peak hydrogen concentration in containment is less that 4.1 v/o.

Hydrogen may accumulate within 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 RCS and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

The hydrogen monitors satisfy Criterion 3 of the NRC Interim Policy Statement.

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BASES (continued)

LCO

Two hydrogen monitors must be OPERABLE with power from two independent safety-related power supplies. Either monitor is capable of obtaining and analyzing a representative sample from the containment dome and the emergency reactor building recirculation-ventilation duct. This assures operation of at least one hydrogen monitor in the event of a worst-case single active failure. Operation of a least one hydrogen monitor will provide the operator with information to enable action to be taken to prevent the containment post-LOCA hydrogen concentration from exceeding the flammability limit.

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

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

[For this facility an OPERABLE hydrogen monitor constitutes the following:]

APPLICABILITY

In MODES 1 and 2, two hydrogen monitors provide the operator with the capability to measure hydrogen concentration in containment assuming a worst-case single active failure and allow, if required, action to be taken to control the hydrogen concentration within containment below its flammability limit of 4.1 v/o following a LOCA. This ensures containment OPERABILITY and prevents damage to safety-related equipment and instrumentation located within containment.

In MODES 3 and 4, 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 hydrogen monitors is low. Therefore, the hydrogen monitors are not required in MODE 3 or 4.

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BASES (continued)

APPLICABILITY (continued)

In MODES 5 and 6, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations of these MODES. Therefore, the hydrogen monitors are not required in these MODES to ensure containment OPERABILITY.

ACTIONS

A.1

With one hydrogen monitor inoperable, the inoperable analyzer must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on the low probability of failure of the other redundant hydrogen monitor, 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 hydrogen recombiners, the Hydrogen Purge System, and the Post-Accident Sampling System.

Concurrent failure of two hydrogen monitors within a 30-day period is considered to be a low probability event. If such double failures would repeatedly occur, it would be indicative of poor hydrogen monitor reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

The plant must be placed in a MODE in which the LCO does not apply if an inoperable hydrogen monitor cannot be restored to OPERABLE status in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 6 hours. The 6-hour Completion Time is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

A CHANNEL FUNCTIONAL TEST is performed on each hydrogen monitor every 92 days to ensure that the entire channel will perform its intended function. The 92-day Frequency is

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

based on the reliability of the hydrogen monitors, which has been demonstrated to be acceptable through operating experience. [For this facility, a CHANNEL FUNCTIONAL TEST constitutes the following:]

SR 3.6.8.2

Performance of a CHANNEL CALIBRATION on the hydrogen monitors using sample gases ensures that the OPERABILITY of the monitors is maintained. A typical CHANNEL CALIBRATION includes a minimum of two data points to verify the accuracy of monitors over the range of interest. The sample gases used for performing the Surveillances are nominally 1 v/o hydrogen, ≥ 0.98 and ≤ 1.02 (balance nitrogen), and nominally 4 v/o hydrogen, ≥ 3.92 and ≤ 4.08 (balance nitrogen). The lower hydrogen flammability limit has been assumed as
4.1 v/o hydrogen in air or steam-air atmospheres (Ref. 1). Therefore, calibration with these sample gases helps ensure the accurate information regarding containment hydrogen concentrations up to and including the flammability limit is available to the operators following a LOCA. For this unit, the 18-month Frequency has been shown to be acceptable through operating experience, and is further justified because of other checks performed during the CHANNEL FUNCTIONAL TEST that convey that proper calibration of hydrogen monitors is being maintained.

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 3.6.9 Hydrogen Recombiners—MODES 1 & 2

BASES

BACKGROUND	Permanently installed hydrogen recombiners are required to reduce the hydrogen concentration in the combiners following a loss-of-coolant accident (LOCA) or steam line break (SLB). The recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor is returned to the containment, thus eliminating any discharge to the environment. Two independent hydrogen recombiner systems are provided. Each consists of controls located in the control room, a power supply, and a recombiner located in containment. The recombiners have no moving parts. Recombination is accomplished by heating a hydrogen-air mixture above 1150°F. The resulting water vapor and discharge gases are cooled prior to discharge from the unit. Air flows through the unit at [illegible]00 cfm, with natural circulation in the unit providing the motive force. A single recombiner is capable of maintaining the hydrogen concentration in containment below the 4.1 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate ENGINEERED SAFETY FEATURE bus, and provided with a separate power panel and control panel.
APPLICABLE SAFETY ANALYSES	The hydrogen recombiners ensure containment OPERABILITY by providing the capability of controlling the bulk hydrogen concentration in containment to less than a concentration of 4.1 v/o, following a Design Basis Accident (DBA). This control would prevent a hydrogen burn inside containment, thus ensuring containment OPERABILITY and minimizing challenges to the OPERABILITY of safety-related equipment located in containment. The limiting DBA relative to hydrogen generation is a LOCA.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Hydrogen may accumulate within 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) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in 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.

The hydrogen recombiners are designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single recombiner is capable of limiting the peak hydrogen concentration in containment to less than 4.1 v/o (Ref. 1). The Hydrogen Purge System is similarly designed such that it is redundant to the hydrogen recombiners.

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

LCO

Two hydrogen recombiners must be OPERABLE with power from two independent safety-related power supplies. Each typically consists of controls, power supply, and recombiner. [For this facility, an OPERABLE hydrogen recombiner constitutes the following:]

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(continued)

DRAFT

BASES (continued)

LCO (continued)

Operation with at least one hydrogen recombiner ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit. Unavailability of both hydrogen recombiners might lead to the generation of a sufficient amount of hydrogen (exceeding the flammability limit) so that it could react with oxygen following the accident. The reaction could take place fast enough to lead to high temperatures and overpressurization of containment and, as a result, breach containment or cause containment leakage rates to exceed those assumed in the safety analyses. Damage to safety-related equipment located in containment could also occur.

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

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

APPLICABILITY

Requiring OPERABILITY in MODES 1 and 2 for the hydrogen recombiners ensures their immediate availability after the safety injection and scram actuated on a LOCA or SLB initiation. In the post-accident LOCA or SLB environment, one hydrogen recombiner is required to control the hydrogen concentration within containment below its flammability limits of 4.1 v/o following a LOCA, assuming a worst-case single failure. This ensures containment OPERABILITY and prevents damage to safety-related equipment and instruments located within containment.

In MODES 3 and 4, 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 hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

(continued)

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BASES (continued)

APPLICABILITY (continued)

In MODES 5 and 6, the probability and consequences of a LOCA are low, due to the pressure and temperature limitations. Therefore, hydrogen recombiners are not required in these MODES to ensure containment OPERABILITY.

ACTIONS

A.1

With one hydrogen recombiner inoperable, the inoperable recombiner 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 or SLB 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 exceeding this limit, the low probability of failure of the OPERABLE hydrogen recombiner, and the availability of the Hydrogen Purge System.

Concurrent failure of two hydrogen recombiners within a 30-day period is considered to be a low-probability event. If such double failures repeatedly occurred, it would be indicative of poor hydrogen recombiner reliability and would result in the loss of functional capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1

The plant must be placed in a MODE in which the LCO does not apply, if the inoperable hydrogen recombiner(s) cannot be restored to OPERABLE status within the associated Completion Time. This is done by placing the plant in at least MODE 3 within 6 hours. The 6 hours allotted to reach MODE 3 is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Performance of a system functional test for each hydrogen recombiner ensures that the recombiners are operational and can obtain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater sheath temperature increases to ≥ 700°F in ≤ 90 minutes. After reaching 700°F, the power is increased to maximum for approximately 2 minutes and power verified to be ≥ 60 kW.

The 18-month Frequency for this SR was developed considering such factors as the following:

a. The incidence of hydrogen recombiners failing the SR in the past is low;

b. Even when hydrogen recombiner failure has been detected, there has been, in all instances, a backup available either from the other recombiner or from a diverse system; and

c. Since the hydrogen recombiner is manually started many hours after a LOCA occurs, there is time available to either restore a recombiner to OPERABLE status or activate an alternative.

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SR 3.6.9.2

This SR ensures that there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failures involve loss of power, 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 hydrogen recombiners failing the SR in the past is low;

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

b. Even when hydrogen recombiner failure has been detected there has been, in all instances, a backup available either from the other recombiner or from a diverse system [Hydrogen Purge System]; and

c. Since the hydrogen recombiner is manually started many hours after a LOCA occurs, there is time available to either restore a recombiner to OPERABLE status or activate an alternative.

SR 3.6.9.3

This SR requires performance of a resistance-to-ground test of each heater phase to ensure 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 $\geq$ 10,000 ohms.

The 18-month Frequency for this SR was developed considering such factors as the following:

a. The incidence of hydrogen recombiners failing the SR in the past is low;

b. Even when hydrogen recombiner failure has been detected, there has been, in all instances, a backup available either from the other recombiner or from a diverse system [Hydrogen Purge System]; and

c. Since the hydrogen recombiner is manually started many hours after a LOCA occurs, there is time available to either restore a recombiner to OPERABLE status or activate an alternative.

REFERENCES

1. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," U.S. Nuclear Regulatory Commission.

DRAFT

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The MSSVs primarily provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary by providing a heat sink for removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Nine MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves (MSIVs), as described in Reference 1. The MSSVs' rated capacity passes the full steam flow at 100% RATED THERMAL POWER (RTP) with the valves full open. This meets the requirements of Section III of the ASME Code (Ref. 2). The MSSV design includes staggered setpoints, as shown in Table 3.7.1-1, so that only the needed number of valves will actuate. Staggered setpoints reduce the potential for valve chattering because of insufficient steam pressure to fully open all valves following a turbine-reactor trip.

The valve lift settings given in Table 3.7.1-1 also meet the requirements of Section III of the ASME Code (Ref. 2). The relief capacity of two of the nine safety valves per steam generator is [583,574] lb/hour and the capacity of the remaining seven is [845,759] lb/hour each. The total relieving capacity for all 18 MSSVs is [14,175,000] lb/hour, which is 120% of the total secondary system flow of [11,760,000] lb/hour at 100% RTP. A maximum safety-valve setpoint pressure of 1100 psig (± 3%) assures that main steam system pressure remains below 110% or 1155 psig. A minimum of two OPERABLE safety valves per steam generator with a combined total relief capacity of at least [1,167,148] lb/hour one with a setpoint not greater than [1050] psig ± 1% and one with a setpoint not greater than [1100] psig ± 1%.

The low-pressure setpoint MSSV, [ ] psia, corresponds to a zero-power loop average temperature (T_{avg}) (secondary fluid saturation temperature) of [ ]°F. The RCS T_{avg} must be above this temperature to open the MSSVs.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the MSSVs comes from the ASME Code and its purpose is to limit secondary system pressure to $\leq$ 110% of design pressure when passing 100% of design steam flow. This design basis is sufficient to cope with any Anticipated Operational Occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and Transient Analysis.

The events that challenge the MSSVs' relieving capacity, and thus RCS pressure, are those characterized as Decreased Heat Removal events, and are presented in Reference 3. Of these, the full power turbine trip coincident with a loss of condenser heat sink is the limiting AOO. For this event, the condenser circulating water system is lost and, therefore, the Turbine Bypass Valves (TBVs) are not available to relieve main steam system pressure. Similarly, MSSV relief capacity is utilized in the FSAR for mitigation of the following events:

a. Loss of normal feedwater;

b. Steam line break (SLB);

c. Steam generator tube rupture (SGTR); and

d. Excessive heat removal due to feedwater system malfunction.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening and failure to reclose once opened. The passive failure mode is failure to open upon demand.

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

LCO

Two MSSVs per steam generator are required by the accident analysis to provide overpressure protection for design basis transients occurring at 102% RTP. However, a MSSV will be considered inoperable if it fails to open upon demand. The LCO requires all MSSVs to be OPERABLE in compliance with the ASME Code, even though this is not a requirement of the Design Basis Accident (DBA) analysis. This is because

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BASES (continued)

LCO (continued)

operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements) and adjustment to the nuclear overpower trip setpoint. These limitations are addressed in Figure 3.7.1-1 and Required Actions A.2.2.1 and A.2.2.2.

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced.

The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Inspection and Testing Program.

The lift settings specified in Table 3.7.1-1 correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their design safety function to mitigate the consequences of accidents that could result in a challenge to the reactor coolant pressure boundary.

APPLICABILITY

In MODE 1 above [ ]% RTP, each steam generator must have the OPERABLE MSSV capacity within the acceptable region of Figure 3.7.1-1. Below [ ]% RTP in MODES 1, 2, and 3, only two MSSVs are required OPERABLE per steam generator.

In MODES 4 and 5, there is no credible transient requiring the MSSVs.

The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES. Should the steam generators be water-solid, however, it is prudent to have overpressure protection for them.

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BASES (continued)

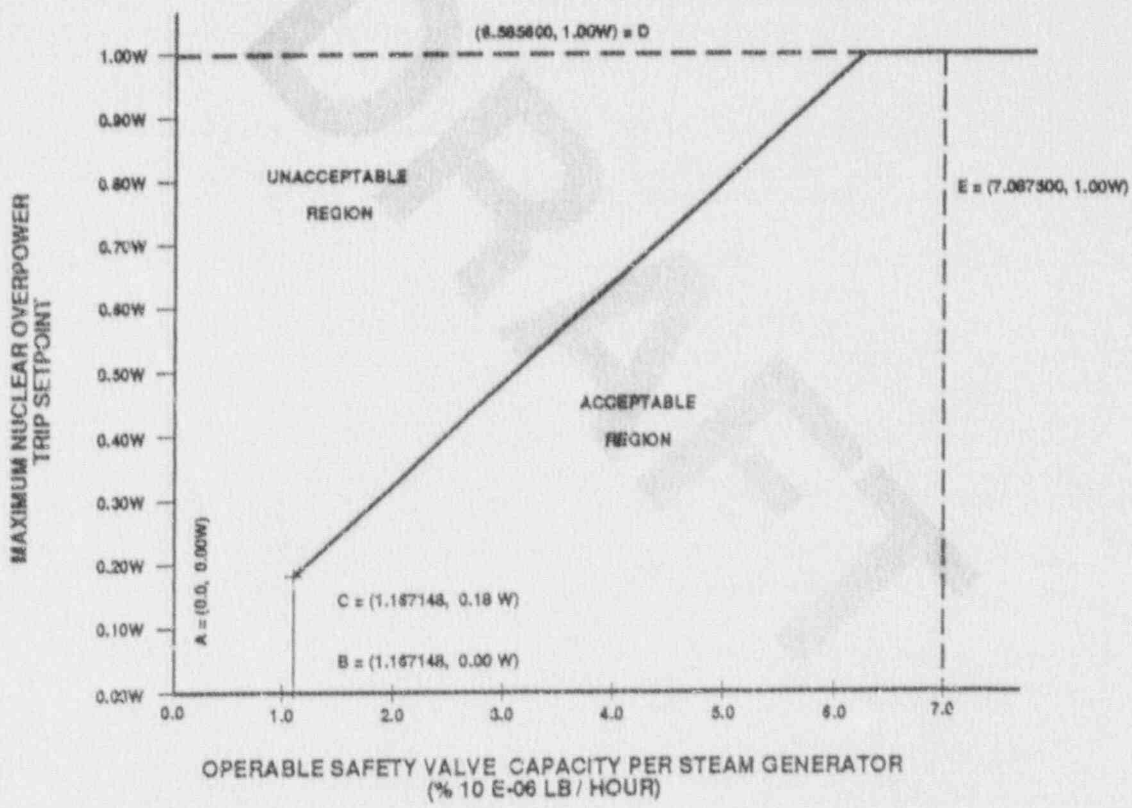

Figure 3.7.1-1

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BASES (continued)

ACTIONS

A.1

With one or more MSSVs inoperable, verify that at least two required MSSVs per steam generator are OPERABLE with each valve from the different lift setting ranges. Only two MSSVs are required in MODES 2 and 3, and only two in MODE 1 below [ ]% RTP. Above [ ]% RTP, the required number of MSSVs to be OPERABLE per steam generator is governed by operation within the acceptable region of Figure 3.7.1-1.

This Action may be satisfied by examining logs or other information to determine if the MSSVs are 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 MSSVs. The 4-hour Completion Time, which is the same as that for restoring a MSSV to OPERABLE status, is a reasonable amount of time to allow for examining information sources, such as maintenance logs, to determine if two MSSVs are OPERABLE, and takes into consideration the low probability of an event occurring during this period that would require activation of the MSSVs.

The Completion Times of Condition A have been provided with a Note to clarify that all MSSVs are treated as an entity for this LCO with a single Completion Time (i.e., the Completion Times are on a Condition Basis).

A.2.1

With one or more MSSVs inoperable, one alternative is to restore the required MSSVs to OPERABLE status per Figure 3.7.1-1. The 4-hour Completion Time to restore a MSSV to OPERABLE status is reasonable, and takes into account the relative importance of maintaining the OPERABILITY of these valves and the low probability of an event occurring during the period that requires activation of the MSSVs.

A.2.2.1 and A.2.2.2

An alternative to restoring the inoperable MSSV(s) to OPERABLE status is to reduce power so that the available MSSV relieving capacity meets ASME Code requirements for the power level. Operation may continue provided the allowable THERMAL POWER and Reactor Protection System nuclear

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(continued)

BASES (continued)

ACTIONS (continued)

overpower trip setpoint are reduced by the formulas

$$RP = \frac{Y}{Z} \times 100\%$$

and

$$SP = \frac{Y}{Z} \times W$$

where:

RP = Reduced THERMAL POWER expressed as a percentage of RTP (not to exceed RTP);

SP = Reduced nuclear overpower trip setpoint (not to exceed W);

W = ALLOWABLE VALUE for Nuclear overpower trip setpoint for four-pump operation as specified in LCO 3.3.1, "Reactor Protection System";

Y = Total OPERABLE relieving capacity per steam generator based on a summation of individual safety-valve relief capacities per steam generator expressed in lb/hour; and

Z = Required relieving capacity per steam generator of 6,585,600 lb/hour.

These equations are graphically represented in Figure 3.7.1-1. Operation is restricted to the area below and to the right of line BCDE.

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(continued)

BASES (continued)

ACTIONS (continued)

The operator should limit the maximum steady-state power level to some value slightly below this setpoint to avoid an inadvertent overpower trip.

The 4-hour Completion Time for Required Action A.2.2.1 is consistent with A.2.1. An additional 4 hours are allowed to reduce the setpoints in recognition of the difficulty of resetting of all channels of this trip function within a period of 4 hours. The Completion Time of 8 hours for Required Action A.2.2.2 is based on operating experience in resetting all channels of a protective function and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status in the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within 6 hours, and in MODE 4 within 12 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 the plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR demonstrates the OPERABILITY of the MSSVs. Section XI, Article 3500, of the ASME Code (Ref. 4) requires that safety- and relief-valve tests be performed as required by ANSI/ASME OM-1-1987 (Ref. 5). Section 7.3.2.1 of Reference 5 requires the following tests for MSSVs:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

e. Verification of the balancing device integrity device on balanced valves.

The ANSI/ASME standard requires the testing of all valves every 5 years, with a minimum 20% of the valves tested every 24 months. The SRs are specified in the Inservice Inspection and Testing Program, which encompasses Section XI of the ASME Code. The ASME Code provides the activities and frequencies necessary to satisfy the requirements.

SR 3.7.1.1 is modified by a Note that allows an exemption to SR 3.0.4. The MSSVs may be either bench tested or tested in-situ at hot conditions using an assist device to simulate lift pressure. The SR 3.0.4 exemption applies to those plants that have provisions for testing the MSSVs at hot conditions. It allows entry into and operation in MODE 3 for the performance of this surveillance. SR 3.0.4 is not applicable to this SR provided testing is completed within 24 hours after reaching acceptable test conditions. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. [Unit Name] FSAR, Section [5.2], "[Overpressure Protection]."

2. ASME Boiler and Pressure Vessel Code, Section III, Article NC-7000, "Overpressure Protection" Class 2 Components.

3. [Unit Name] FSAR, Section [15.2], "[Accident Analysis—Decreased Heat Removal Events]."

4. ASME Boiler and Pressure Vessel Code, Section XI, Article IWV-3500, "Inservice Tests—Category C Valves."

5. ANSI/ASME OM-1-1987, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices."

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high-energy line break. MSIV closure terminates flow from the unaffected (intact) steam generator.

One MSIV is located in each main steam line outside of, but close to, containment. The MSIVs are downstream from the MSSVs and emergency feedwater pump turbine's steam supply to prevent their being isolated from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the other, and isolates the turbine, steam bypass system, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a Steam and Feedwater Rupture Control System (SFRCS) signal generated by either low steam generator pressure or steam generator-to-feedwater differential pressure. The MSIVs fail closed on loss-of-control or actuation power. The MSIVs may also be actuated manually.

A description of the MSIVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment (Ref. 2). It is also influenced by the accident analysis of the SLB events presented in Reference 3. The design precludes the blowdown of more than one steam generator, assuming a single active component failure (i.e., the failure of one MSIV to close on demand.)

The limiting case for the containment analysis is the SLB inside Containment with a loss-of-offsite power following turbine trip and failure of the MSIV on the affected steam generator to close. At 100% RATED THERMAL POWER (RTP), the steam generator inventory and temperature are at their maximum, maximizing the mass and energy release to the containment.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Due to reverse flow, failure of the MSIV to close contributes to the total release the additional mass and energy in the steam headers downstream of the other MSIV. Other failures considered are the failure of a main feedwater isolation valve (MFIV) to close, and failure of an emergency diesel generator (EDG) to start.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at full power is the limiting case for a post-trip return to power. The analysis includes scenarios with offsite power available and with a loss-of-offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System (RCS) cooldown. With a LOOP, the response of mitigating systems, such as the high pressure injection (HPI) pumps, is delayed. Significant single failures considered include failure of a MSIV to close, failure of an EDG, and failure of a HPI pump.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. High-energy line break, SLB, or main feedwater line breaks, inside containment. In order to maximize the mass and energy release into the containment, the analysis assumes the MSIV in the affected steam generator remains open. For this scenario, steam is discharged into containment from both steam generators until closure of the MSIV in the intact steam generator occurs. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIV in the intact loop.

b A SLB outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs. Events such as increased steam flow through the turbine or the steam bypass valves will also terminate on closing the MSIVs.

d. Following a steam generator tube rupture (SGTR), closure of the MSIVs isolates the ruptured steam generator from the intact steam generator. In addition to minimizing radiological releases, this enables the operator to maintain the pressure of the steam generator with the ruptured tube below the MSIVs setpoints, a necessary step toward isolating flow through the rupture.

e. The MSIVs are also utilized during other events such as a feedwater line break.

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

LCO

This LCO requires that the MSIV in both steam lines be OPERABLE. The MSIVs are considered OPERABLE when their isolation times are within limits and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 limits or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

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

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

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BASES (continued)

APPLICABILITY

The MSIVs must be OPERABLE whenever there is significant mass and energy in the RCS and steam generator. This ensures that in the event of a high-energy line break, a single failure cannot result in the blowdown of more than one steam generator.

In MODES 1, 2, and 3, there is significant mass and energy; therefore, the MSIVs must be OPERABLE or closed. When the valves are closed, they are already performing their safety function.

In MODE 4, the MSIVs are normally shut, and the steam generator energy is low.

In MODES 5 and 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high-energy secondary-system pipe breaks in these MODES.

A Note has been added to provide clarification that the Completion Time is on a Condition Basis; Condition A and Conditions (C and D) Completion Times are independent.

ACTIONS

A.1

With one MSIV inoperable, time is allowed to restore the component to OPERABLE status. Some repairs can be made to the MSIV with the plant hot. The 8-hour Completion Time is reasonable, considering the probability of an accident that would require actuation of the MSIVs occurring during this time interval.

The 8-hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation. With more than one MSIV inoperable in MODE 1, the facility is in a Condition outside the accident analysis; therefore, LCO 3.0.3 must be entered immediately.

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BASES (continued)

ACTIONS (continued)

B.1 and B.2

If the MSIV cannot be restored to OPERABLE status within 8 hours, the MSIV must be closed within the next 6 hours. Six hours is a reasonable time to complete the actions required to close the MSIV, which include performing a controlled plant shutdown to MODE 2. The Completion Time is based on plant operating experience related to the time required to reach MODE 2 with the MSIVs closed, in an orderly manner and without challenging plant systems.

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

With one MSIV inoperable in MODES 2 or 3 in one or more flow paths, restore MSIVs to OPERABLE status, or close inoperable MSIVs within 8 hours. The remaining OPERABLE MSIV in each flow path will ensure that the flow path can be isolated if an event were to occur that required isolation by these valves. The Completion Time of 8-hours takes into account the redundancy afforded by the OPERABLE MSIV and the low probability of a Design Basis Accident (DBA) that would require closure of the MSIVs occurring during this period.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time but are closed, the inoperable MSIVs must be verified to be continually closed on a periodic basis. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 12-hour Completion Time is based on engineering judgment and is considered reasonable in view of MSIV status indications available in the control room and other administrative controls that will ensure that these valves will continue to be in the closed position.

D.1 and D.2

With two MSIVs inoperable in MODE 2 or 3 in the same flow path for one or more flow paths, restore at least one MSIV to OPERABLE status in each affected flow path or close at least one inoperable MSIVs in each affected flow path in 1 hour. In this situation, the facility is in a Condition outside the assumptions in the Accident Analyses. The 1-hour Completion Time provides a period of time to correct the problem commensurate with the importance of bringing the

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BASES (continued)

ACTIONS (continued)

facility within the assumptions of the Accident Analyses. This time period also ensures that the probability of an accident (requiring main steam line isolation) occurring during periods where two MSIVs are inoperable in the same flow path is minimal.

E.1 and E.2

The plant must be placed in a MODE in which the LCO does not apply if the MSIV cannot be restored to OPERABLE status or closed in the associated Completion Time. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience related to the time required to reach the required MODES from MODE 2 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

The MSIV closure time is assumed in the accident and containment analyses. This surveillance is normally performed upon returning the plant to operation following a refueling outage, because the MSIVs should not be tested at power since even a part-stroke exercise increases the risk of a valve closure with the plant generating power. As the MSIVs are not to be tested at power, they are exempt from the ASME Section XI requirements (Ref. 4) during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Inspection and Testing Program or 18 months, whichever is less. The 18-month surveillance Frequency to demonstrate the valve closure time is based on the refueling cycle.

Operating experience has shown that those components usually pass the surveillance when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

This test is conducted in MODE 3, with the plant at operating temperature and pressure, as part of the ASME Section XI (Ref. 4) exercising requirements. SR 3.7.2.1 is modified by a Note that allows exemption to SR 3.0.4. SR 3.0.4 is not applicable to this SR for entry into MODE 3 provided testing is completed within 24 hours after reaching acceptable test conditions. This allows delaying testing in MODE 3 in order to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. [Unit Name] FSAR, Section [10.3], "[Main Steam System]."

2. [Unit Name] FSAR, Section [6.2], "[Containment Analysis]."

3. [Unit Name] FSAR, Section [15.4], "[Steam Line Break Analysis]."

4. American Society for Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400, "Inservice Tests—Category A and B Valves."

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs) and Associated Bypass Valves

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high-energy line break. Closure of the MFIVs and associated bypass valves terminates flow to both steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs. The consequences of events occurring in the main steam lines or in the feedwater lines downstream of the MFIVs will be mitigated by their closure. Closing the MFIVs and associated bypass valves effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line break or FWLBs inside Containment and reducing the cooldown effects for steam line breaks (SLBs).

The MFIVs and associated bypass valves isolate the non-safety-related portions from the safety-related portion of the system. In the event of a secondary-side pipe rupture inside containment, the valves limit the quantity of high-energy fluid that enters containment through the break and provides a pressure boundary for the controlled addition of emergency feedwater (EFW) to the intact loop.

One MFIV and its associated bypass valve is located on each main feedwater line, outside but close to containment. The MFIVs are located upstream of the EFW injection point so that EFW may be supplied to the steam generators following MFIV closure. The piping volume from this valve to the steam generator must be accounted for in calculating mass and energy releases, and refilled prior to EFW reaching the steam generator following either an SLB or FWLB.

The MFIVs for each steam generator consist of the main feedwater stop valve, MFIVs, and main feedwater control (startup control valves). The MFIVs and its associated bypass valves close on receipt of a Steam and Feedwater Rupture Control System (SFRCS) generated by either low steam generator pressure or main MFW steam generator differential pressure. The SFRCS also provides input to the Anticipatory Reactor Trip System to trip the MFW pumps. The MFIVs can also be closed manually.

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BASES (continued)

BACKGROUND (continued)

The MFIVs and its associated bypass valves close on receipt for a safety injection—low T_{avg} coincident with reactor trip or steam generator water level—high-high signal. They may also be actuated manually. In addition to the MFIVs and its associated bypass valves, a check valve inside containment is available to isolate the feedwater line penetrating containment and to ensure that the consequences of events do not exceed the capacity of the containment heat removal systems.

A description of the MFIVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs is established by the analysis for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs and its associated bypass valves may also be relied on to terminate a steam break for core response analysis and excess feedwater event upon the receipt of a steam generator water level—high-high signal or a main steam isolation signal (MSIS) on high steam generator level.

Failure of a MFIV and its associated bypass valves to close following a SLB, FWLB, or excess-feedwater event, can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following a SLB or FWLB event.

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

LCO

Following a FWLB or a main steam line break (MSLB), this LCO ensures that the MFIVs and their associated bypass valves will isolate MFW flow to the steam generators. These valves will also isolate the non-safety-related portions from the safety-related portions of the system.

This LCO requires that the MFIV and its associated bypass valve in each of the feedwater lines be OPERABLE. The MFIVs and their associated bypass valves are considered OPERABLE

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(continued)

BASES (continued)

LCO (continued)

when their isolation times are within limits and they close on an isolation-actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following a SLB or FWLB inside containment. If the SFRCS on high steam generator level is relied on to terminate an excess-feedwater-flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

[For this facility, the following support systems are required to be OPERABLE to ensure the main feedwater valves OPERABILITY:]

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

APPLICABILITY

The MFIVs and their associated bypass valves must be OPERABLE whenever there is significant mass and energy in the RCS and steam generators. This ensures that in the event of a high-energy line break, a single failure cannot result in the blowdown of more than one steam generator.

In MODES 1, 2, and 3, the MFIVs and their associated bypass valves are required to be OPERABLE in order to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed, they are already performing their safety function.

In MODE 4, steam generator energy is low and the MFIVs and their associated bypass valves are normally closed since MFW is not required. In MODES 5 and 6, the steam generators do not contain much energy because their temperature is below the boiling point of water. Therefore, the MFIVs and their associated bypass valves are not required for isolation of potential high-energy secondary-system pipe breaks in these MODES.

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BASES (continued)

APPLICABILITY (continued)

For this LCO, a Note has been added to provide clarification that Conditions A and B are treated as an entity with a single Completion Time.

ACTIONS

A.1, A.2.1 and A.2.2

With one MFIV or its associated bypass valve in one or more flow paths inoperable, restore affected valves to OPERABLE status, or close or isolate inoperable affected valves within [8 or 72] hours. When these valves are closed or isolated, they are performing their required safety function (i.e., to isolate the line).

The typical arrangement assumed in these actions is a bypass valve in parallel with an MFIV. If an MFIV or bypass valve is inoperable and open under these conditions, then it is assumed that the closed system inside containment will function to isolate the line.

[(For plants with only one MFIV per feedwater line): The 8-hour Completion Time is a reasonable amount of time to complete the actions required to close the MFIV or its associated bypass valve which includes performing a controlled plant shutdown to MODE 2. The Completion Time is based on plant operating experience related to the time required to reach MODE 2 with the MFIVs closed in an orderly manner and without challenging plant systems.]

The 72-hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event that would require isolation of the main feedwater flow paths occurring during this period.

For inoperable MFIVs and their associated bypass valves that cannot be restored to OPERABLE status within the specified Completion Time, but were closed or isolated, the inoperable valves must be verified that they continue to be closed or isolated on a periodic basis. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 12-hour Completion Time is based on engineering judgment, and is considered reasonable in view of valve status indications available in the control room and other

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(continued)

BASES (continued)

ACTIONS (continued)

administrative controls that will ensure that these valves will continue to be in the closed or isolated position.

B.1 and B.2

If more than one MFIV or its associated bypass valves in the same flow path cannot be restored to OPERABLE status, then there may be no redundant system to operate automatically and perform the required safety function. Although the containment can be isolated with the failure of two valves in parallel in the same flow path, the double failure is likely to be a precursor of a common mode failure in the valves of this flow path and as such is treated the same as a loss of the isolation capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status or closed or affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8-hour Completion Time is a reasonable time to complete the actions required to close the MFIV or its associated bypass valve, which includes performing a controlled plant shutdown to MODE 2. The Completion Time is based on plant operating experience related to the time required to reach MODE 2 with the MFIVs closed in an orderly manner and without challenging the plant systems.

C.1 and C.2

If the MFIVs and their associated bypass valves cannot be restored to OPERABLE status or closed or isolated 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 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power operation in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

The MFIV closure time is assumed in the accident and containment analyses. This surveillance is normally

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(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

performed upon returning the plant to operation following a refueling outage. The MFIVs should not be tested at power since even a part-stroke exercise increases the risk of a valve closure with the plant generating power. As these valves are not tested at power, they are exempt from the ASME, Section XI requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Inspection and Testing Program or 18 months, whichever is less. The surveillance interval of 18 months for valve closure time is based on the refueling cycle. Operating experience has shown that these components usually pass the SR when performed on the 18-month Frequency.

SR 3.7.3.1 is modified by a Note that allows exemption to SR 3.0.4. SR 3.0.4 is not applicable to this SR for entry into MODE 3 provided testing is completed within 24 hours after reaching acceptable test conditions. This allows delaying testing in MODE 3 in order to establish conditions consistent with the conditions under which the acceptance criterion was generated.

REFERENCES

1. [Unit Name] FSAR, Section [10.4.7], "[Condensate and Feedwater System]."

3.7 PLANT SYSTEMS

B 3.7.4 Emergency Feedwater (EFW) System

BASES

BACKGROUND

The EFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System (RCS) upon the loss of normal feedwater supply. The EFW pumps take suction through separate and independent suction lines from the condensate storage tank (CST) (LCO 3.7.5), and pump to the steam generator secondary side through the EFW nozzles. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1), or atmospheric dump valves (ADVs) (LCO 3.7.11). If the main condenser is available, steam may be released via the steam bypass system and recirculated to the CST.

[The following system description is provided as an example that should be provided by the specific unit. The EFW System consists of two turbine-driven EFW pumps, each of which provides a nominal 100% capacity, and one non-safety-grade motor-driven EFW pump. The steam turbine-driven EFW pumps receive steam from either of the two main steam headers, upstream of the main steam isolation valves (MSIVs). The EFW supplies a common header capable of feeding either or both steam generators. The 100% capacity is sufficient to remove decay heat and cool the plant to decay heat removal (DHR) entry conditions. The EFW System normally receives a supply of water from the CST (LCO 3.7.5). A safety-grade source of water is also supplied by the Service Water System (SWS). Automatic valves on the supply piping open on low pressure in the supply piping to transfer the water supply from the CST to the SWS. A third source of water can be supplied by manually aligning the fire protection header to the EFW pump suction.] Thus the requirements for diversity in motive power sources for the EFW System are met.

The EFW System can supply feedwater to the steam generators during normal plant startup, shutdown, and hot standby conditions.

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BASES (continued)

BACKGROUND (continued)

The EFW System is designed to supply sufficient water to cool the plant to DHR entry conditions with steam being released through the ADVs and condenser.

The EFW actuates automatically on low steam generator level, low steam generator pressure, steam generator or feedwater differential pressure, or loss of four reactor coolant pumps by the Steam and Feedwater Rupture Control System (SFRCS) as described in LCO 3.3.2.

The EFW System is discussed in References 1 and 2.

APPLICABLE SAFETY ANALYSES

The EFW System mitigates the consequences of any event with a loss of normal feedwater.

The design basis of the EFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3%.

In addition, the EFW System must supply enough makeup water to replace steam generator secondary inventory being lost as steam as the unit cools to MODE 4 conditions. Sufficient EFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the EFW System are:

a. Feedwater system pipe rupture; and

b. Loss of normal feedwater.

In addition, the minimum available EFW flow and system characteristics are serious considerations in the analysis of a small-break loss-of-coolant accident (LOCA).

[The EFW System designed is such that it can perform its function following a loss of the turbine-driven main feedwater pumps or a feedwater line break, combined with a loss of normal or reserve electric power.]

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

EFW satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

This LCO provides assurance that the EFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary (RCPB). [Three] independent EFW pumps, in two diverse trains, ensure the availability of residual heat removal capability for all events accompanied by a loss-of-offsite power and a single failure. [This is accomplished by powering two of the pumps by steam-driven turbines supplied with steam from a source that is not isolated by the closure of the MSIVs, and one pump from a power source that, in the event of loss-of-offsite power, is supplied by the emergency diesel generator.]

The EFW System is considered OPERABLE when the components and flow paths required to provide EFW flow to the steam generators are OPERABLE. This requires that the [two] turbine-driven EFW pump(s) be OPERABLE with redundant steam supplies from each of the main steam lines upstream of the MSIVs and capable of supplying EFW flow to either of the two steam generators. The [two non-safety-grade] motor-driven EFW pump(s) and [their] associated flow path(s) to the EFW System [are] als required to be OPERABLE. The piping, valves, instrumentation and controls in the required flow paths shall be OPERABLE instrumentation. The primary and secondary sources of water to the EFW System, as well as the flow path from the primary and secondary sources of water of the EFW System to all of the EFW pumps, are required to be OPERABLE. [Individual plants should describe their specific primary and secondary sources of water to the EFW Systems that are required to be OPERABLE.]

The LCO is modified by a Note requiring only the motor-driven EFW pump in MODE 4. This is because of reduced heat-removal requirement, the short duration of MODE 4 in which feedwater is required, and the insufficient steam supply available in MODE 4 to power the turbine-driven AFW pump.

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BASES (continued)

LCO (continued)

[For this facility, each OPERABLE EFW train constitutes the following:] [For this facility, support systems for the EFW system are as follows:]

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

APPLICABILITY

In MODES 1, 2, and 3, the EFW System is required to be OPERABLE and to function in the event that the main feedwater is lost. In addition, the EFW system is required to supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions.

In MODE 4, without a decay heat removal (DHR) loop OPERABLE and in operation, the EFW system is required to be used for heat removal via the steam generators. In MODE 4, the steam generators are being used for heat removal until the decay-heat-removal system is in operation.

In MODES 5 and 6, the steam generators are not used for decay-heat removal and the EFW System is not required.

For this LCO, a Note has been added to provide clarification that all components of the EFW trains are treated as an entity with a single Completion Time.

ACTIONS

A.1

With one of the two steam supplies to the turbine-driven EFW train(s) inoperable, action must be taken to restore the steam supply to OPERABLE status. The 7-day Completion Time is justified based on:

a. The redundant OPERABLE steam supply to the turbine driven EFW pump(s);

b. The availability of redundant OPERABLE motor-driven EFW pumps; and

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BASES (continued)

ACTIONS (continued)

c. The low probability of an event occurring that would require the inoperable steam supply to the turbine-driven EFW pump(s).

B.1

If one of the required EFW trains (pump or flow path) is inoperable, action must be taken to restore the train to OPERABLE status. This Condition includes the loss of two steam supply lines to one of the turbine-driven EFW pumps. The 72-hour Completion Time was chosen in light of the redundant capabilities afforded by the EFW System, reasonable time for repairs, and the low probability of a DBA event occurring during this period. Two EFW pumps and flow paths remain to supply feedwater to the steam generators.

C.1 and C.2

When either Required Action A.1 or Required Action B.1 cannot be completed within the required Completion Time, or when two EFW trains are inoperable, the plant must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 4 (except as indicated in a Note applicable to Required Action C.2) within 18 hours. Required Action C.2 has been modified by a Note intended to restrict entry into MODE 4 without any DHR loops OPERABLE and in operation. The Note also is intended to convey the suspension of further action to reach MODE 4, if while in Required Action C.2, all DHR loops become inoperable or are not in operation. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power operation in an orderly manner and without challenging plant systems.

In MODE 4, with two EFW trains inoperable, operation is allowed to continue because only one motor-driven EFW train is required in accordance with the Note that modifies the LCO. Although not required, the plant may continue to cool down and initiate decay heat removal, if prudent.

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BASES (continued)

ACTIONS (continued)

D.1

With all three EFW trains inoperable, the plant is in a seriously degraded condition with no safety-related means for conducting a cooldown, and only limited means for conducting a cooldown with non-safety-grade equipment. In such a condition, the plant should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore at least one EFW train to OPERABLE status.

Required Action D.1 is modified by a Note to suspend all required MODE changes or power reductions until at least one EFW train is restored to OPERABLE status. LCO 3.0.3 is not applicable, as it could force the plant into a less safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the EFW water and steam flow paths, provides assurance that the proper flow paths exist for EFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since those valves were verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This surveillance 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.

The 31-day Frequency of this SR was derived from Inservice Inspection and Testing requirements for performing valve testing at least once every 92 days. The Frequency was further justified in view of the procedural controls governing valve operation and to provide added assurance of valve correct positions.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.2

This SR demonstrates that the EFW pumps develop sufficient discharge pressure to deliver the required flow at the full open pressure of the MSSVs. Because it is undesirable to introduce cold EFW into the steam generators while they are operating, this test is performed on recirculation flow.

Periodically comparing the reference differential pressure developed at this reduced flow detects trends that might be indicative of incipient failure. Inservice testing of Section XI of the ASME Code (Ref. 3), required only at 3-month intervals, satisfies this requirement when performed per Specification 6.8.1.j, "Inservice Inspection and Testing Program."

A 31-day Frequency on a STAGGERED TEST BASIS results in testing each pump once per 3 months, as required by the ASME Code.

SR 3.7.4.2 is modified by a Note to allow an exception to SR 3.0.4. Provisions of SR 3.0.4 are not applicable for entry into MODE 3 for purposes of testing the turbine-driven EFW pump, because the amount of steam in MODES 4, 5, and 6 is insufficient to perform a valid test.

SR 3.7.4.3

This SR ensures that EFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates a SFRCS signal by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. The actuation logic is tested every 92 days as part of the SFRCS functional test except for the subgroup relays that actuate the system that cannot be tested during normal plant operations. The 18-month Frequency was developed considering it is prudent that these surveillances only be performed during a plant outage. This is due to the plant conditions needed to perform the SRs and the potential for unplanned plant transients if the SRs are performed with the reactor at power. The 18-month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.4

This SR ensures that the turbine-driven EFW pumps will start in the event of any accident or transient that generates a SFRCS signal by demonstrating that each turbine-driven EFW pump starts automatically on an actual or simulated actuation signal. The actuation logic is tested every 92 days as part of the SFRCS functional test, except for the subgroup relays that actuate the system that cannot be tested during normal plant operation. The 18-month Frequency justification is the same as that for SR 3.7.4.3. SR 3.7.4.2 is modified by a Note to suspend the provisions of SR 3.0.4 for entry into MODE 3 for purposes of testing the turbine-driven EFW pump, because the steam pressure in MODES 4, 5, and 6 is insufficient to perform a valid test. SR 3.0.4 is not applicable to this SR for entry into MODE 3 provided testing is completed within 24 hours after reaching acceptable test conditions.

SR 3.7.4.5

This SR ensures that the EFW System is properly aligned by demonstrating the flow path to each steam generator prior to entering MODE 2 after more than 30 days in MODE 5 or 6. Operability of EFW flow paths must be demonstrated before sufficient core heat is generated that would require the operation of the EFW System during a subsequent shutdown. The Frequency is based on engineering judgment and is considered adequate in view of other administrative controls that ensure that flow paths remain OPERABLE. For added assurance, the OPERABILITY of the flow paths is verified following extended outages to determine that there is no misalignment of valves. This SR ensures that the flow path from the CST to the steam generator is properly aligned by requiring a verification of flow capacity of at least [750] gpm at [1270] psig or equivalent. (This SR is not required by those plants that use EFW for normal startup and shutdown.)

SR 3.7.4.6 and SR 3.7.4.7

[For this facility, the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION for the EFW pump suction pressure interlocks are as follows:]

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BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section 9.2.7, "[Emergency Feedwater System]."

2. [Unit Name] FSAR, Section 9.2.8, "[Emergency Feedwater System]."

3. American Society for Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400, "Inservice Tests: Category A and B Valves."

DRAFT

B 3.7 PLANT SYSTEMS

B 3.7.5 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a safety-grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Emergency Feedwater (EFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves (MSSVs) or the atmospheric vent valves (AVVs).

When the main steam isolation valves (MSIVs) are open, the preferred means of heat removal is to discharge steam to the condenser by the non-safety-grade path of the steam bypass valves. The condensed steam is returned to the CST by the condensate transfer pump. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena, as well as missiles that might be generated by natural phenomena. The CST is designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from an alternate source(s). [For this facility, the alternate source(s) of feedwater and their safety-grade classification are as follows:]

A description of the CST is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The CST provides cooling water to remove decay heat and cool down the plant following all events in the accident analysis (Ref. 2 and Ref. 3). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 30 minutes at MODE 3, steaming through the MSSVs, followed by a cooldown to decay heat removal (DHR) entry conditions at the design cooldown rate.

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APPLICABLE SAFETY ANALYSES (continued)

The limiting event for the condensate volume is the large feedwater line break coincident with a loss-of-offsite power. Single failures that also affect this event include:

a. Failure of the diesel generator powering the motor-driven EFW pump to the unaffected steam generator (requiring additional steam to drive the remaining EFW pump's turbine); and

b. Failure of the steam-driven EFW pump (requiring a longer time for cooldown using only one motor-driven EFW pump).

These are not usually the limiting failures in terms of consequences for these events.

A non-limiting event considered in CST inventory determinations is a break, either in the main feedwater line, or the EFW line near where the two join. This break has the potential for dumping condensate until terminated by operator action, as the Emergency Feedwater Actuation System (EFAS) would not detect a difference in pressure between the steam generators for this break location. This loss-of-condensate inventory is partially compensated by the retaining of steam generator inventory.

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

LCO

To satisfy accident analysis assumptions, the two CSTs must contain sufficient cooling water to remove decay heat for 13 hours following a reactor trip from 102% RATED THERMAL POWER and then to cool down the RCS to DHR system entry conditions, assuming a coincident loss-of-offsite power and most adverse single failure. While so doing, the CSTs must retain sufficient water to ensure adequate net positive suction head (NPSH) for the EFW pump(s) during the cooldown, as well as to account for any losses from the steam-driven EFW pump's turbine, or before isolating EFW to a broken line.

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BASES (continued)

LCO (continued)

The level required is equivalent to a usable volume of [250,000] gallons which is based on holding the plant in MODE 3 for 2 hours followed by a cooldown to DHR system entry conditions at 100°F/hour. This basis, established by Branch Technical Position, Reactor Systems Branch 5-1 (Ref. 4), exceeds the volume required by the accident analysis.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the applicability of the CST is consistent with that required for EFW System applicability, since the CST directly supports the EFW System.

In MODES 5 and 6, the CST is not required because the EFW System is not required.

ACTIONS

A.1

If one or more CSTs are unable to supply the required volume of cooling water to the EFW pumps, the CST(s) must be restored to OPERABLE status. Four hours allows sufficient time to restore the required volume in the CST(s) from the condenser or backup supply, and is a reasonable time to limit the risk from accidents requiring the plant to cool down.

If equipment used to verify CST level is determined to be inoperable, the CST level is considered to be out of limits and Required Actions A.1 and A.2.2 Completion Times apply to restore such equipment to OPERABLE status.

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BASES (continued)

ACTIONS (continued)

A.2.1 and A.2.2

As an alternative to shutting down the plant, the OPERABILITY of the backup supply may be verified. The OPERABILITY of the backup feedwater supply must include verification of the OPERABILITY of flow paths from the backup supply to the EFW pumps and availability of the required volume of water in the backup supply. The CST must still be returned to OPERABLE status within 7 days because the backup supply may be performing this function in addition to its normal functions. Based on operating experience, the 4-hour Completion Time is a reasonable amount of time to verify the OPERABILITY of the backup water supply. The 7-day Completion Time is reasonable in view of the fact that an OPERABLE backup water supply is available, and the low probability of an event requiring the use of the water from the CST(s) occurring during this period. [For this facility, an OPERABLE backup water supply to the EFW System constitutes the following:]

B.1 and B.2

If the CST cannot be restored to OPERABLE status in the associated Completion Time, the plant must be placed in a MODE in which the requirement does not apply with the DHR system in operation. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 4 (except as indicated in a note applicable to Required Action B.2) within 18 hours. This allows an additional 6 hours for the DHR system to be placed in service after entering MODE 4. Required Action B.2 has been modified by a Note intended to restrict entry into MODE 4 without an RHR train OPERABLE and in operation. The Note also is intended to convey the suspension of further action to reach MODE 4 if, while in Required Action B.2, all RHR trains become inoperable or are not in operation.

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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies that the CST(s) contain(s) the required volume of cooling water. The 12-hour Frequency of this SR was developed based on operating experience, and in view of operator awareness of plant evolutions that may affect the CST inventory between checks. Also, the 12-hour Frequency is considered adequate in view of other indications, including alarms available in the control room to alert the operator of abnormal CST level deviations.

REFERENCES

1. [Unit Name] FSAR, Section [9.2.6], "[Condensate Storage and Transfer System]."
2. [Unit Name] FSAR, Section [6], "[Engineered Safety Features]."
3. [Unit Name] FSAR, Section [15], "[Accident Analysis]."
4. NRC Standard Review Plan Branch Technical Position (BTP) RSB 5-1, "Design Requirements for the Residual Heat Removal System."

B 3.7 PLANT SYSTEMS

B 3.7.6 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube out-LEAKAGE from the Reactor Coolant System (RCS). Under steady-state conditions, the activity is primarily iodines with relatively short half-lives and, thus, indicative of current conditions. During transients, I-131 spikes have been observed, as well as increased releases of some noble gases. Other fission-product isotopes, as well as activated corrosion products, in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environs because of normal operation, anticipated operational occurrences (AOOs), and accidents.

This limit is lower than the activity value that might be expected from a 1-gpm tube leak (LCO 3.4.14) of primary coolant at the limit of 1.0 μCi/gram (LCO 3.4.17). The steam-line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant leakage. Most of the iodine isotopes have short half-lives (i.e., less than 20 hours). I-131, with a half-life of 8.04 days, concentrates faster than it decays, but does not reach equilibrium because of blowdown and other losses.

With the specified activity limit, the resultant 2-hour thyroid dose to a person at the exclusion area boundary (EAB) would be about 0.79 rem if the main steam safety valves (MSSVs) are open for the 2 hours following a trip from full power.

Operating a plant at the allowable limits could result in a 2-hour EAB exposure of a small fraction of the 10 CFR 100 (Ref. 1) limits, or the limits established as the NRC staff-approved licensing basis.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB) (Ref. 2) assumes the initial secondary-coolant specific activity to have a radioactive isotope concentration of 0.1 μCi/g DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed a small fraction of the plant EAB limits of 10 CFR 100 for whole-body and thyroid dose rates.

With a loss-of-offsite power, the remaining steam generator is available for core decay-heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator atmospheric dump valves (ADVs). The Emergency Feedwater (EFW) System supplies the necessary makeup to the steam generator. Venting continues until the reactor coolant temperature and pressure has decreased sufficiently for the Shutdown Cooling (SDC) System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary Specific Activity satisfies criterion 3 of the NRC Interim Policy Statement.

LCO

As indicated in the applicable safety analyses, the specific activity limit in the secondary coolant system of ≤ 0.1 μCi/g DOSE EQUIVALENT I-131 maintains the radiological consequences of a Design Basis Accident (DBA) to a small fraction of 10 CFR 100 (Ref. 1).

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BASES (continued)

LCO (continued)

Monitoring the specific activity of the secondary coolant ensures that, when secondary specific activity limits are exceeded, appropriate actions are taken, in a timely manner, to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply whenever the steam generators are used for RCS heat removal. This is a potential time for secondary steam releases to the atmosphere, carrying with the steam a portion of the activity in the steam generators.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary-to-secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS, and contributes to increased post-accident doses. If secondary specific activity cannot be restored to within limits in the associated Completion Time, the plant must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full-power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR ensures that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post-accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31-day Frequency takes into consideration the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

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 [15], "[Accident Analysis]."

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety-related components during a transient or accident. During normal operation, the CCW System also provides this function for various nonessential components, as well as the spent fuel pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System (SWS), and thus to the environment.

A typical CCW System is arranged as two independent full-capacity cooling loops, and has isolatable nonsafety-related components. Each safety-related train includes a full-capacity pump, surge tank, heat exchanger, piping, valves, and instrumentation. Each safety-related train is powered from a separate bus. An open surge tank in the system provides pump trip protective functions to ensure sufficient net positive suction head (NPSH) is available. The pump in each train is automatically started on receipt of a safety injection actuation signal (SIAS), and all nonessential components are isolated. [For this facility, the CCW System consists of the following:]

Additional information on the design and operation of the CCW System, along with a list of the components served, are presented in Reference 1. The principal safety-related function of the CCW System is the removal of decay heat from the reactor via the [decay heat removal (DHR) heat exchanger]. This may utilize the DHR System during a normal or post-accident cooldown and shutdown, or during the recirculation phase following a loss-of-coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is to provide cooling water to the Emergency Core Cooling System (ECCS) and emergency diesel generator (EDG) during DBA conditions. The CCW System also supplies cooling water to EDGs during a loss-of-offsite power. [For this facility, the

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

interactions between EDGs and CCW System are as follows:] Both CCW loops are in operation while cooling the primary system to below [280]°F and maintaining primary temperature below [140]°F for refueling operations. The length of time two pumps are required is dependent on decay-heat load, reactor auxiliary load, and service water temperature. One loop is capable of cooling the primary system to less than [212]°F in less than [24] hours with a minimum auxiliary heat load and an [85]°F service wate. temperature.

The CCW System is designed to perform its function with a single failure of any active component assuming a loss-of-offsite power.

The CCW System also functions to cool the plant from [SCS] entry conditions (T_{cold} <[350]°F to MODE 5 (T_{cold} <[200]°F) during normal and post-accident operations. The time required to cool from [350]°F to [200]°F is a function of the number of CCW and [SCS] trains operating. One train is sufficient to remove decay heat during subsequent operations with T_{cold} <[200]°F. This assumes that a maximum sea water temperature of [76]°F occurs simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies, and the operation of one train does not depend on the other. In the event of a Design Basis Accident (DBA), one train of CCW is required to provide the minimum heat-removal capability assumed in the safety analysis for systems to which it supplies cooling water. To ensure this is met, two trains of CCW must be OPERABLE. At least one train will operate assuming the worst-case single active failure occurs coincident with loss-of-offsite power.

A train is considered OPERABLE when:

a. It has an OPERABLE pump and associated surge tank; and

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BASES (continued)

LCO (continued)

b. The associated piping, valves, heat exchanger, and instrumentation and controls on the safety-related flow path are OPERABLE.

The isolation of CCW from other components or systems not required for safety may render these components or systems inoperable, but does not affect the OPERABILITY of the CCW System. [For this facility, the following support systems are required to be OPERABLE to ensure CCW System OPERABILITY:]

[For this facility, the main systems supported by the CCW system and the justification for not declaring the main systems inoperable upon failure of the CCW System are as follows:]

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system that must be prepared to perform its post-accident safety functions, primarily Reactor Coolant System (RCS) heat removal, by cooling the DHR heat exchanger.

In MODES 5 and 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

If one CCW train is inoperable, the inoperable CCW train must be restored to OPERABLE status within 72 hours. In this condition, the remaining OPERABLE CCW train is adequate to perform the heat-removal function. The 72-hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

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BASES (continued)

ACTIONS (continued)

B.1

With one CCW train inoperable, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support CCW train 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 B.

Required Action B.1 ensures that those identified Required Actions associated with supported systems impacted by the inoperability of CCW trains have been initiated. This can be accomplished by entering the supported systems LCOs, or independently as a group of Required Actions that 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 CCW train inoperable, and one or more required support or supported features inoperable associated with the other redundant CCW train, enter Required Actions or Condition D. Condition C is indicative of loss-of-CCW System functional capability.

D.1, D.2, D.3, and D.4

If the CCW train cannot be restored to OPERABLE status in the associated Completion Time, or if two CCW trains are inoperable, 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 6 hours, and in MODE 4 within 12 hours.

If both trains are inoperable, action must be taken immediately to restore at least one train to OPERABLE status. In this case, there is a no heat sink for the [DHR System], thus one CCW train must be restored to OPERABLE status, and the plant should be maintained in MODE 4, where decay heat can be removed by the steam generators.

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BASES (continued)

ACTIONS (continued)

With both trains inoperable, flexibility is left to the operator (and abnormal operating procedures) to manage the situation. This allows remaining in MODE 4 with an alternate means of heat removal. This action allows total loss of function without entry into MODE 5 as required by LCO 3.0.3, which may not be possible with two CCW trains inoperable. When a CCW train is restored to OPERABLE status, then the plant should be placed in MODE 5. In this case, LCO 3.0.3 is not applicable as the plant cannot be brought to MODE 5 without at least one train of CCW OPERABLE. Adequate heat removal can be maintained using the steam generators and natural circulation.

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 3.7.7.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW 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. This SR also does not apply to valves which cannot be inadvertently misaligned, such as check valves. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of potentially being mispositioned are in their correct position.

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 was further justified in view of the procedural control governing valve operation, and as a means of providing added assurance of correct valve positions.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR demonstrates proper automatic operation of the CCW valves. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The [18]-month Frequency was developed since it is considered prudent that many surveillances only be performed during a plant outage. This is due to the plant conditions needed to perform the SR, and the potential for unnecessary 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. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.7.7.3

This SR demonstrates proper automatic operation of the CCW pumps. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The [18]-month Frequency was developed since it is considered prudent that many surveillances only be performed during a plant outage. This is due to the plant conditions needed to perform the SR, and the potential for unnecessary 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. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [9.2.2], "[Component Cooling Water System]."

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety-related components during a transient or Design Basis Accident (DBA). During normal operation and normal shutdown, the SWS also provides this function for various safety-related and non-safety-related components. The safety-related position is covered by this LCO.

A typical SWS consists of two separate, 100%-capacity safety-related cooling water trains. Each train consists of two 100%-capacity pumps, one component cooling water (CCW) heat exchanger, piping, valving, instrumentation, and cyclone separator. The pumps and valves are remote manually aligned, except in the unlikely event of a loss-of-coolant accident (LOCA). The pumps aligned to the critical loops are automatically started upon receipt of a safety injection signal (SIS), and all essential valves are aligned to their post-accident positions. In addition to the CCW System, the SWS also provides cooling directly to the Control Room Emergency Ventilation System (CREVS) water-cooled condensing unit, the Emergency Core Cooling System (ECCS) pump room coolers, containment air cooler, and turbine driven cooling-water system. The system is also a source of water to the Emergency Feedwater (EFW) pumps, and can provide a source of makeup water to the cooling tower. [For this facility the SWS consists of the following:]

Additional information about the design and operation of the SWS, along with a list of the components served, is presented in Reference 1. The principal safety-related function of the SWS is the removal of decay heat from the reactor via the [CCW System].

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is for one SWS train, in conjunction with the CCW System and a 100%-capacity Containment Cooling System, removing core decay heat following a design basis LOCA (Ref. 2). This prevents the containment sump fluid from increasing in temperature during

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

the recirculation phase following a LOCA, and provides for a gradual reduction in the temperature of this fluid, as it is supplied to the Reactor Coolant System (RCS) by the safety injection pumps.

The SWS is designed to perform its function with a single failure of any active component, assuming loss-of-offsite power.

The SWS, in conjunction with the CCW System, also cools the plant from decay-heat-removal system (Ref. 3) entry conditions to MODE 5 during normal and post-accident operation. The [illegible] required for this evolution is a function of the number of CCW and decay-heat-removal system trains that are operating. One SWS train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum SWS temperature of [95]°F occurring simultaneously with maximum heat loads on the system.

The SWS is also required when needed to support CCW in the removal of heat from the emergency diesel generators (EDGs) or reactor auxiliaries.

The SWS satisfies of Criterion 3 of the NRC Interim Policy Statement.

LCO

Two SWS trains 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 train is considered OPERABLE when:

a. It has an OPERABLE pump; and

The associated piping, valves, instrumentation, heat exchanger, and cyclone separator on the safety-related flow path are OPERABLE.

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BASES (continued)

LCO (continued)

The isolation of the SWS from other components or systems not required for safety, may render those components or systems inoperable, but does not affect the OPERABILITY of the SWS.

[For this facility, the main systems supported by SWS and the justification for not declaring the main systems inoperable upon failure of SWS are as follows:]

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that must be prepared to perform its post-accident safety functions, primarily RCS heat removal, by cooling the CCW System, and thus the [DHR System heat exchanger].

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

A.1

If one SWS train is inoperable, it must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SWS train is adequate to perform the heat-removal function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1

With one SWS train inoperable, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support SWS train within a Completion Time of [ ] hours.

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BASES (continued)

ACTIONS (continued)

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 inoperability of SWS trains 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 B of this LCO.]

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

C.1

With one SWS train inoperable, and one or more required support or supported features inoperable associated with the other redundant SWS train, enter Required Actions of Condition D. Condition C is indicative of a loss-of-SWS-functional capability.

D.1, D.2, D.3, and D.4

If the SWS train cannot be restored to OPERABLE status within the associated Completion Time, or two SWS trains are inoperable, 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 6 hours, and in MODE 4 within 12 hours. If both trains are inoperable, action must be taken to restore at least one train to OPERABLE status. In this case, there is no heat sink for the [DHR heat exchanger], thus one SWS train shall be restored to OPERABLE status immediately. The plant should be maintained in MODE 4 until one SWS train is restored to OPERABLE status.

When a SWS train is OPERABLE, the plant should be placed in MODE 5. This allows total loss of function without entry into LCO 3.0.3, because entry into MODE 5, as required by LCO 3.0.3, may not be desirable with two SWS trains inoperable.

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BASES (continued)

ACTIONS (continued)

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 3.7.8.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the SWS flow path provides assurance that the proper flow paths exist for SWS 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. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This surveillance 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.

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 was further justified in view of the procedural control governing valve operation, and to provide added assurance of correct valve positions.

SR 3.7.8.2

This SR demonstrates proper automatic operation of the SWS valves. The SWS is a normally operating system that cannot be fully actuated as part of the normal testing. The 18-month Frequency was developed because this surveillance can only be prudently performed during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for unnecessary 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. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.3

The SR demonstrates proper automatic operation of the SWS pumps. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 18-month Frequency was developed because this surveillance can only be prudently performed during a plant outage. This is due to the plant conditions needed to perform the SR and the potential for unnecessary 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 an 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. [Unit Name] FSAR, Section [9.2.1], "[Service Water System]."
2. [Unit Name] FSAR, Section [6.2], "[Containment Analysis]."
3. [Unit Name] FSAR, Section [ ], "[Decay Heat Removal]."

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for process and operating heat from safety-related components during a transient or accident. This is done utilizing the Service Water System (SWS).

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 the sources with, but not including, the cooling water system intake structures (Ref. 1). If cooling towers or portions thereof are required to accomplish the UHS safety functions, they should meet the same requirements as the sink. The two principal meet functions of the UHS are the dissipation of residual heat after a reactor shutdown, and dissipation of residual heat after an accident.

A variety of complexes is 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 structure, it is likely that a second source will have been required.

The basic performance requirements are that a 30-day supply of water be available, and that the design basis 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 another source(s) and a makeup system(s) 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 source(s) become of sufficient importance that the makeup system itself may be required to meet the same design criteria as an engineered safety feature (ESF) (e.g., single-failure 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

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BASES (continued)

BACKGROUND (continued)

in OPERABILITY determinations and in SRs. The Actions and SRs are illustrative of a cooling tower UHS without a makeup requirement. [Development of UHS Technical Specifications for plants with cooling towers and makeup systems may require Actions and SRs for components in addition to cooling tower fans (e.g., makeup pumps and isolation valves).]

[For plants without cooling towers, additional Actions and SRs may be necessary (e.g., a second source or use of spray ponds).]

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1. [For this facility, the UHS consists of the following:]

If the UHS does not meet its design limits of water temperature, water level, or number of OPERABLE cooling tower fans, the UHS may not have sufficient capacity to bring the plant to a safe controlled shutdown during a Design Basis Accident (DBA) from full power, but may be able to support plant operations at a reduced power level.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removal from the reactor core following all accidents and anticipated operational occurrences in which the plant is cooled down and placed on [decay-heat removal]. Its maximum post-accident heat load occurs 20 minutes after a design basis loss-of-coolant accident (LOCA). Near this time, the plant switches from injection to recirculation and the Containment Cooling Systems are required to remove the core decay heat.

The operating limits are based on conservative heat-transfer analyses for the worst-case LOCA. Reference 1 provides the details of the assumptions used in the analysis. These assumptions include: worst-expected meteorological conditions, conservative uncertainties when calculating decay heat, and the worst-case failure (e.g., single failure of a man-made structure). The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30-day supply of cooling water in the UHS.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The UHS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

The UHS is considered OPERABLE if [it contains a sufficient volume of water at or below the maximum temperature] that would allow the SWS to operate for at least 30 days following the design-basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature should not exceed [90°F], and the level should not fall below [562 ft Mean Sea Level] during normal plant operation.

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

[For this facility, the following are support systems for the UHS:]

[For this facility, the following main systems are supported by the UHS and the justification for not declaring the main systems inoperable upon failure of the UHS:]

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to be OPERABLE to ensure sufficient cooling capacity and must be prepared to perform its post-accident safety functions. An example is Reactor Coolant System (RCS) heat removal for core decay heat.

In MODES 5 and 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

Required Action A.1 assures the required cooling capacity will be available should a Design Basis Accident (DBA) occur.

This action may be satisfied by examining logs or other information to determine if the cooling tower may 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 D must be entered immediately.

For Action A.2, with one cooling tower fan per cooling tower inoperable, the inoperable cooling tower fans must be restored to OPERABLE status within 7 days or action must be taken to reduce power. The specified Completion Time is consistent with other LCOs for the 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.

The Completion Times of Condition A have been provided with a Note to clarify that all UHS cooling tower fans are treated as an entity for this LCO, with a single Completion Time (i.e., the Completion Times are on a Condition basis).

B.1

With the UHS inoperable as established by Condition D, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support cooling tower fans 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 B.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

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

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

C.1

With one or more cooling tower fans inoperable, and one or more required support or supported features associated with the other redundant cooling tower inoperable, 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.

D.1 and D.2

If the cooling tower fan cannot be restored to OPERABLE status within the associated Completion Time, or if the UHS is inoperable for reasons other than Condition A, the plant must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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 3.7.9.1

This SR ensures that adequate long-term (30 days) cooling can be maintained. The level specified ensures enough NPSH is available for operating the SWS pumps. The 24-hour Frequency is based on operating experience related to the trending of the parameter variations during the applicable MODES.

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

This SR verifies that the SWS can cool the CCW system to at least its maximum design heat loads for 30 days following a DBA. The [24-hour] Frequency is based on operating experience related to the trending of the parameter variations during the applicable MODES.

SR 3.7.9.3

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 UHS cooling tower fans occurring between surveillances. It has also been shown to be acceptable through operating experience.

REFERENCES

1. [Unit Name] FSAR, Section [9.2.5], "[Ultimate Heat Sink]."

2. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," Revision 2, January 1976.

3.7 PLANT SYSTEMS

B 3.7.10 Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the fuel storage pool meets the assumption of iodine decontamination factors following a fuel-handling accident. The specified water level shields and minimizes the general-area dose when the storage racks are at their maximum capacity. The water also provides shielding during the movement of spent fuel. If normal cooling is lost, the water provides about a 12-hour heat sink before boiling occurs.

A general description of the fuel storage pool design is given in Reference 1, and the Spent Fuel Pool Cooling and Cleanup System is given in Reference 2. The assumptions of the fuel-handling accident are given in Reference 3.

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the fuel-handling accident described in Regulatory Guide 1.25 (Ref. 4). The resultant two-hour thyroid dose to a person at the exclusion area boundary (EAB) is a small fraction of the 10 CFR 100 (Ref. 5) limits.

The assumption of Regulatory Guide 1.25, preserved by this Specification, is that there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface for a fuel-handling accident. With 23 ft, the assumptions of Regulatory Guide 1.25 can be used directly. In practice, the LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel rack, however, there may be < 23 ft above the top of the fuel bundle and the surface, by the width of the bundle. To offset this small nonconservatism, the analysis assumes that all fuel rods fail, although the analysis shows that only the first [four] rows fail from a hypothetical maximum drop.

The fuel storage pool water level satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

The specified water level preserves the assumptions of the fuel-handling accident analysis (Ref. 3). As such, it is the minimum required for fuel storage and movement within the fuel storage pool.

[For this facility, the following constitutes an OPERABLE fuel shortage pool water level:]

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

[For this facility, those required support systems which, upon their failure, do not require declaring the 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 occurrence of an accident. With the fuel storage pool at less than the required level, the movement of spent fuel is immediately brought to a halt in a safe position. This effectively precludes the occurrence of a spent-fuel-handling accident. In such a case, plant procedures control the movement of loads over the spent fuel.

In the event that the required fuel storage pool water level channels are determined inoperable, the fuel storage pool water level is considered to be not within limits, and Required Actions A.1 and A.2 apply to restore the instrumentation channels to OPERABLE status.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

A.2

Action to restore the water level should commence immediately, and be carried through to completion.

Required Action A.1 and Required Action A.2 are modified by a Note that allows an exemption to LCO 3.0.3 and LCO 3.0.4. Both LCOs are not applicable, as events in the fuel storage pool are not affected by either MODE level or facility operations.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

This SR verifies that sufficient water is available in the event of a fuel-handling accident. The water level in the fuel storage pool must be checked periodically. The 7-day Frequency is appropriate in view of the fact that the volume in the pool is normally stable. Water level changes are controlled by plant procedures and have been proven to be acceptable through operating experience.

During refueling operations, the level in the fuel pool is at equilibrium with that in 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 [9.1.2], "[Spent Fuel Storage]."

2. [Unit Name] FSAR, Section [9.1.3], "[Spent Fuel Pool Cooling and Cleanup System]."

3. [Unit Name] FSAR, Section [15.4.7], "[Fuel Handling Accident]."

4. Regulatory Guide 1.25 (Rev. 00), "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."

(continued)

(continued)

BASES (continued)

REFERENCES (continued)	5.	Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area Low Population Zone and Population Center Distance."

DRAFT

B 3.7 PLANT SYSTEMS

B 3.7.11 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADVs provide a method for cooling the plant to decay heat removal (DHR) entry conditions, should the preferred heat sink via the Steam Bypass System to the condenser not be available (Ref. 1). This is done in conjunction with the Emergency Feedwater (EFW) System, providing cooling water from the condensate storage tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Steam Bypass System.

Two ADV lines are provided per steam generator. Each ADV line consists of one ADV and its associated block valve.

The ADVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ADVs are typically provided with a pressurized gas supply of bottled nitrogen which, on loss of pressure in the normal instrument air supply, automatically supplies nitrogen to operate the ADVs. The nitrogen supply is sized to provide sufficient pressurized gas to operate the ADVs for the time required for Reactor Coolant System (RCS) cooldown to DHR entry conditions.

A description of the ADVs is found in Reference 1. In addition, the ADVs are OPERABLE with only a dc power source available. Hand wheels are provided for local manual operation. [For this facility, the ADVs and their support systems consist of the following:]

APPLICABLE SAFETY ANALYSES

The design basis of the ADVs is established by the capability to cool the plant to DHR entry conditions. The design rate of [75]°F/hour is applicable for both steam generators, each with two ADVs. This rate is adequate to

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

cool the plant to DHR entry conditions with only one ADV and one steam generator utilizing the cooling water supply available in the CST.

In the accident analysis presented in the FSAR, the ADVs are assumed to be used by the operator to cool down the plant to DHR entry conditions for accidents accompanied by a loss-of-offsite power. Prior to the operator actions to cool down the plant, the ADVs and the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator's pressure and temperature below the design value. This is typically 30 minutes following initiation of an event. (This may be less for a steam generator tube rupture (SGTR) event.) The limiting events are those which render one steam generator unavailable for RCS heat removal with a coincident loss-of-offsite power, this results from a turbine trip and the single failure of one ADV on the unaffected steam generator. Typical initiating events falling into this category are a main steam line break (MSLB) upstream of the main steam isolation valves, a feedwater line break (FWLB), and an SGTR event (although the ADVs on the affected steam generator may still be available following an SGTR event).

For the recovery from an SGTR event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary-to-secondary break flow into the ruptured steam generator. After the break flow is terminated, the operator would then continue the cooldown to DHR conditions, similar to the cooldown for other events. The operator is assumed to use only the ADVs on the non-ruptured steam generator to perform the limited cooldown required to terminate the break flow, and subsequently to cool down the plant to DHR entry conditions. The time required to terminate the primary-to-secondary break flow for an SGTR is more critical than the time required to cool down to DHR conditions for this event, and also for other accidents. Thus, the SGTR is the limiting event for the ADVs. The number of ADVs required to be OPERABLE to satisfy the SGTR accident analysis requirements depends upon the consideration of any single-failure assumptions regarding the failure of one ADV to open on demand.

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

The design must accommodate the single failure of one ADV to open on demand, thus each steam generator must have at least two ADVs. The ADVs are equipped with block valves in the event an ADV spuriously fails open, or fails to close during use.

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

LCO

Two ADV lines are required on each steam generator to ensure that at least one ADV is OPERABLE to conduct a plant cooldown following an event in which one steam generator becomes unavailable, accompanied by a single-active failure of one ADV line on the unaffected steam generator. The block valves must be OPERABLE to isolate a failed open ADV. A closed-block valve does not render it or its ADV line inoperable if operator action time to open the block valve is supported in the accident analysis.

Failure to meet the LCO can result in the inability to cool the plant to DHR entry conditions following an event in which the condenser is unavailable for use with the Steam Bypass System.

An ADV is considered OPERABLE when it is capable of providing a controlled relief of the main steam flow, and is capable of fully opening and closing on demand.

[For this facility, the following constitutes an OPERABLE ADV line:]

[For this facility, the support systems required OPERABLE to ensure the ADV lines OPERABILITY are as follows:]

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the ADV lines provide the path for cooling the RCS to DHR entry conditions following an SGTR.

(continued)

(continued)

BASES (continued)

APPLICABILITY (continued)

In MODES 5 and 6, an SGTR is not a credible event.

For this LCO, a Note has been added to provide clarification that all ADV lines are treated as an entity with a single Completion Time.

ACTIONS

A.1

With one ADV line inoperable, action should be taken to return the inoperable ADV line to OPERABLE status. The 7-day Completion Time takes into account the redundant capability afforded by the remaining OPERABLE ADV lines, and a non-safety-grade backup in the Steam Bypass System and MSSVs. A Note has been added to this Required Action to indicate that the provisions of LCO 3.0.4 do not apply.

B.1

With more than one ADV line inoperable, action must be taken to restore at least [three] ADV lines to OPERABLE status. As the block valve can be closed to isolate an ADV, some repairs may be possible with the plant at power. The 24-hour Completion Time takes into account sufficient time to repair inoperable ADV lines, the availability of the Steam Bypass System and MSSVs, and the low probability of an event occurring during this period that requires the ADV lines.

C.1 and C.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies the OPERABILITY of the ADVs. To perform a controlled cooldown of the RCS, the ADVs must be able to be opened and throttled through their full range. This SR ensures that the ADVs are tested through a full controlcycle at least once per fuel cycle. Performance of inservice testing or use of an ADV during a plant cooldown may satisfy this requirement. 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 3.7.11.2

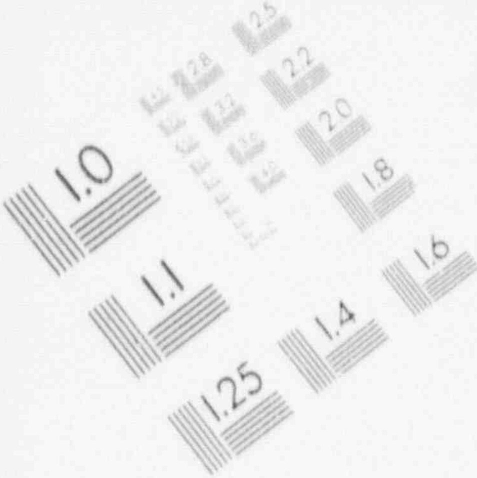
This SR verifies the OPERABILITY of the block valves. The function of the block valve is to isolate a failed open ADV. Cycling the block valve closed and open demonstrates its ability to perform this function. Performance of inservice testing or use of the block valve during plant cooldown may satisfy this requirement. 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.

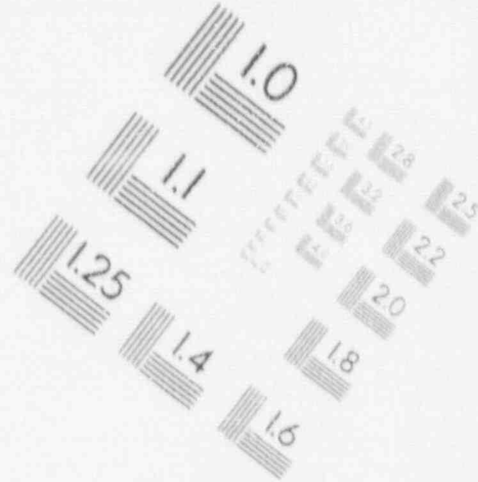
REFERENCES

1. [Unit Name] FSAR, Section [10.3], "[Main Steam Supply System]."

2

IMAGE EVALUATION TEST TARGET (MT-3)





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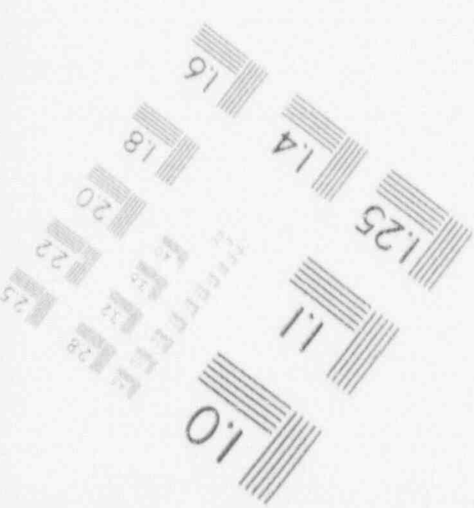

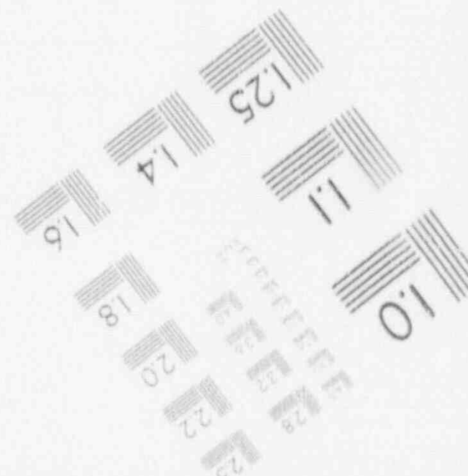

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B 3.7 PLANT SYSTEMS

B 3.7.12 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The CREVS provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity, chemicals, or toxic gas.

The CREVS consists of two independent, redundant, fan-filter assemblies. Each filter train consists of a roughing filter, a high efficiency particulate air (HEPA) filter, and a charcoal filter. A cooling coil and a water-cooled condensing unit are provided for each system to provide suitable temperature conditions in the control room for operating personnel and safety-related control equipment. Ductwork, valves or dampers, and instrumentation also form part of the system. Two redundant air-cooled condensing units are provided as a backup to the water-cooled condensing unit. Both water-cooled and air-cooled condensing units must be OPERABLE for the CREVS to be OPERABLE.

The CREVS is an emergency system. Upon receipt of the activating signal(s), the normal control room ventilation system is automatically shut down and the CREVS can be manually started. The roughing filters and water-condensing units remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the high-efficiency and charcoal filters.

A single train will pressurize the control room with a 1.5-ft^2 LEAKAGE area to about 1/8-inch water gauge, and provide an air exchange rate in excess of 25% per hour. The CREVS operation is discussed in Reference 1.

The CREVS is designed to maintain the control room for 30 days of continuous occupancy after a Design Basis Accident (DBA), without exceeding a 5-rem whole-body dose.

APPLICABLE SAFETY ANALYSES

The CREVS components are arranged in redundant safety-related ventilation trains. The location of components and ducting within the control room envelope ensures an adequate

(continued)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

supply of filtered air to all areas requiring access. During emergency operation, the CREVS maintains the temperature between 70°F and 85°F. The CREVS provides airborne radiological protection for the control room operators as demonstrated by the control room accident dose analyses for the most limiting design basis loss-of-coolant accident (LOCA) fission-product release presented in Reference 2.

The worst-case single-active failure of a CREVS component, assuming a loss-of-offsite power, does not impair the ability of the system to perform its design function.

[For this facility, there are no sources of toxic chemicals that could be released to affect control room habitability.]

The CREVS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two independent and redundant CREVS trains are required to ensure that at least one is available if a single failure disables the other train. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a large radioactive release.

The CREVS is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both trains. A train is considered OPERABLE when it associated:

1. Fan is OPERABLE;

2. HEPA filter and charcoal absorber are not excessively restricting flow, and are capable of performing their filtration functions;

3. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained; and

4. SRs are met.

(continued)

(continued)

BASES (continued)

LCO (continued)

In addition, the control room boundary, including the integrity of the walls, floors, ceilings, ductwork, and access doors, must be maintained.

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

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

APPLICABILITY

In MODES 1, 2, 3 and 4, the CREVS must be OPERABLE to ensure that the control room will remain habitable during and following a DBA.

[In MODES 5 and 6, the CREVS may be required to cope with the release from rupture of a waste-gas tank.]

During movement of irradiated fuel, the CREVS must be OPERABLE to cope with a release due to a fuel-handling accident.

ACTIONS

A.1

With one CREVS train inoperable, the inoperable CREVS train must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the control room radiation protection function. The 7-day Completion Time is based on the low probability of a DBA occurring during this time period, and the consideration that the remaining train can provide the required capability.

Concurrent failure of two CREVS trains would result in the loss-of-function capability. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

In MODES 1, 2, 3, or 4, when Required Action A.1 cannot be completed within the required Completion Time, the plant

(continued)

(continued)

ACTIONS (continued)

must be placed in a MODE that minimizes accident risk. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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

In MODE 5 or 6, or during movement of irradiated fuel, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CREVS train should immediately be placed in the emergency mode. This action ensures that the remaining train is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected. Required Action C.1 is modified by a Note to place the system in the emergency mode if auto-swapower to emergency mode is inoperable.

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

An alternative to Required Action C.1 is to immediately suspend activities that could release radioactivity that might enter the control room. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

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

In MODES 5 and 6, and during movement of irradiated fuel, when two CREVS trains are inoperable, the Required Action is to immediately suspend activities that could release radioactivity that could enter the control room. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies that a train 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 environment and normal operating conditions on this system are not severe, testing each train

(continued)

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

once every month adequately checks this system. Monthly heater operations dry out any moisture that has accumulated in the charcoal because 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-train redundancy available.

SR 3.7.12.2

The Ventilation Filter Testing Program (VFTP) encompasses all the CREVS filter tests consistent with Reference 3. The VFTP includes testing HEPA filter performance, charcoal absorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.12.3

This SR verifies that each CREVS train starts and operates on an actual or simulated actuation signal. The Frequency of 18 months is specified in Reference 3.

SR 3.7.12.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of the potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify that the CREVS is functioning properly. During the emergency mode of operation, the CREVS is designed to pressurize the control room to ≥ [0.125] inches water gauge positive pressure, with respect to adjacent areas, to prevent unfiltered inleakage. The CREVS is designed to maintain this positive pressure with one train at a recirculation flow rate of ≤ [3000] cfm. The Frequency of 18 months is consistent with the guidance provided in Reference 4.

SR 3.7.12.5

[For this facility, the purpose of this SR is as follows:]

(continued)

BASES (continued)

REFERENCES

1. [Unit Name] FSAR, Section [9.4], "[Air Conditioning, Heating, Cooling, and Ventilation]."
2. [Unit Name] FSAR, Section [15], "[Accident Analysis]."
3. Regulatory Guide 1.52 (Rev. 02), "Design, Testing and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants."
4. NUREG-0800, "Standard Review Plan," Section 6.4, "Control Room Habitability System," Rev. 2, July 1981.

DRAFT

B 3.7 PLANT SYSTEMS

B 3.7.13 Control Room Emergency Air Temperature Control System (CREHVAC)

BASES

BACKGROUND

The CREHVAC provides temperature control for the control room following isolation of the control room.

The CREHVAC consists of two independent, redundant trains that provide cooling and heating of recirculated control room air. Each train consists of a cooling coil, water-cooled condensing unit and heating coils that provid for control room temperature, and the safety-related control equipment. The CREHVAC is a subsystem providing air temperature control for the Control Room Emergency Ventilation System (LCO 3.7.12).

The CREHVAC is an emergency system. On detection of high containment building pressure or radiation, low Reactor Coolant System pressure, or high noble-gas radioactivity in the station vent, the normal control room ventilation system is automatically shut down and the CREVS can be manually started. A single train will provide the required temperature control. The CREHVAC operation to maintain control room temperature is discussed in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the CREHVAC is to maintain control room environment habitability for 30 days of continuous occupancy.

The CREHVAC components are arranged in redundant, safety-related trains. During emergency operation, the CREHVAC maintains the temperature between [70]°F and [95]°F. A single-active failure of a CREHVAC component does not impair the ability of the system to perform as designed. The CREHVAC is designed in accordance with Seismic Category I requirements. The CREHVAC is capable of removing sensible- and latent-heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

The CREHVAC satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

Two independent and redundant trains of the CREHVAC are required to ensure that at least one is available, assuming a single failure disables the other train. Total system failure could result in the control room becoming uninhabitable, and equipment-operating temperature exceeding limits in the event of an accident.

The CREHVAC is considered OPERABLE when the individual components that are necessary to maintain control room temperature are OPERABLE in both trains. These components include the cooling coils, water-cooled condensing units, and associated temperature-control instrumentation. In addition, the CREHVAC must be OPERABLE to the extent that air circulation can be maintained.

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

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

APPLICABILITY

In MODES 1, 2, 3, 4, and during movement of irradiated fuel, the CREHVAC must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY requirements following isolation of the control room.

In MODES 5 and 6, CREHVAC may not be required for those facilities which do not require automatic control room isolation.

ACTIONS

A.1

With one CREHVAC train inoperable, the inoperable CREHVAC train must be restored to OPERABLE status within 30 days.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

During this period, the remaining OPERABLE CREHVAC train is adequate to maintain the control room temperature within limits. 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 capabilities, and the alternate safety- or non-safety-related cooling means that are available. [For this facility, the alternate cooling means are as follows:]

Concurrent failure of two CREHVAC trains would result in the loss of function capability; therefore, LCO 3.0.3 must be entered immediately.

B.1 and B.2

In MODE 1, 2, 3 or 4, when Required Action A.1 cannot be completed within the required Completion Time, the plant must be placed in a MODE that minimizes accident risk. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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 without challenging plant systems.

C.1

In MODE 5 or 6, or during movement of irradiated fuel, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CREHVAC train should be placed in operation immediately. This action ensures that the remaining train is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

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

An alternative to Required Action C.1 is to immediately suspend activities that could release radioactivity that might require the isolation of the control room. This places the plant in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

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BASES (continued)

ACTIONS (continued)

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

When in MODE 5 or 6, or during movement of irradiated fuel, with two CREHVAC trains inoperable, the Required Action is to immediately suspend activities that could release radioactivity that might require isolation of the control room. This places the plant in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies that the ability of the system to remove heat meets design requirements. This SR is performed every 18 months and consists of a combination of testing and calculations. An 18-month Frequency is appropriate as significant degradation of the CREHVAC is slow and is not expected over this time period.

REFERENCES

1. [Unit Name] FSAR, Section [9.4], "[Air Conditioning, Heating, Cooling, and Ventilating System]."

B 3.7 PLANT SYSTEMS

B 3.7.14 Emergency Ventilation System (EVS)

BASES

BACKGROUND

The EVS filters air from the area of the active Emergency Core Cooling System (ECCS) components during the recirculation phase of a loss-of-coolant accident (LOCA). The EVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the ECCS pump room area and the lower reaches of the auxiliary building.

The EVS consists of two independent, redundant trains. Each train consists of a heater, a prefilter or demister, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, and instrumentation also form part of the system, as well as demisters functioning to reduce the relative humidity of the air stream. A second bank of HEPA filters follows the adsorber section to collect carbon fines and to provide backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the accident analysis, but serves to collect charcoal fines and to back up the upstream HEPA filter if it should develop a leak. The system initiates filtered ventilation of the pump room following receipt of a Safety Injection Actuation Signal (SIAS).

The EVS is a standby system, aligned to bypass the system HEPA filters and charcoal adsorbers. During emergency operations, the EVS dampers are realigned, and fans are started to begin filtration. Upon receipt of the actuating Engineered Safety Feature Actuation System (ESFAS) signal(s), normal air discharges from the ECCS pump room, the pump room is isolated, and the stream of ventilation air discharges through the system's filter trains. The prefilters or demisters remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The purge system is connected to the EVS by means of ductwork bypasses and dampers. In the event of a

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BASES (continued)

BACKGROUND (continued)	fuel-handling accident that results in the release of radioactivity during fuel-handling operations inside containment, the EVS filters can be used for containment cleanup. The Fuel Storage Pool Ventilation System (FSPVS) is also connected to the EVS through a ductwork bypass with redundant dampers. The FSPVS is the subject of LCO 3.7.15, and is fully described in Reference 2. The EVS is discussed in several sections of the FSAR (Refs. 1, 2, and 3), since it may be used for normal, as well as post-accident, atmospheric cleanup functions. The primary purpose of the heaters is to maintain the relative humidity at an acceptable level consistent with iodine-removal efficiencies per Regulatory Guide 1.52 (Ref. 4).
APPLICABLE SAFETY ANALYSES	The design basis of the EVS is established by the large-break LOCA. The system evaluation assumes a passive failure of the ECCS outside containment, such as a safety injection (SI) pump-seal failure during the recirculation mode. In such a case, the system limits radioactive release to within 10 CFR 100 (Ref. 6) limits or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). The analysis of the effects and consequences of a large-break LOCA is presented in Reference 3. The EVS also actuates following a small-break LOCA, requiring the plant to go into the recirculation mode of long-term cooling, and to cleanup releases of smaller leaks, such as from valve stem packing. Two types of system failures are considered in the accident analysis: complete loss-of-function, and excessive LEAKAGE. Either type of failure may result in a lower efficiency of removal of any gaseous and particulate activity released to the ECCS pump rooms following a LOCA. Following a LOCA, an ESFAS signal starts the EVS fans and opens the dampers located in the penetration room outlet ductwork. The ESFAS signal closes all containment isolation valves and purge system valves. The purge system fans, if running, are shut down automatically. The EVS satisfies Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

Two independent and redundant trains of the EVS are required to ensure that at least one is available, assuming that a single failure disables the other train coincident with loss-of-offsite power. Total system failure could result in atmospheric release from the negative pressure area boundary exceeding 10 CFR 100 limits in the event of a Design Basis Accident (DBA).

The EVS is considered OPERABLE when the individual components necessary to maintain the negative pressure area boundary filtration are OPERABLE in both trains.

A train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

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

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

d. SRs are met.

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

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

[For this facility, the main systems supported by the EVS and the justification for not declaring the main systems inoperable upon failure of the EVS are as follows:]

APPLICABILITY

In MODES 1, 2, 3, and 4, the EVS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODES 5 and 6, the EVS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

(continued)

BASES (continued)

ACTIONS

A.1

With one EVS train not OPERABLE, the inoperable train must be restored to OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the EVS safety function.

The 7-day Completion Time is appropriate because the risk contribution is less than that of the ECCS (72-hour Completion Time), and this system is not a direct support system for the ECCS. The 7-day Completion Time is based on the low probability of a DBA occurring during this time period, and the consideration that the remaining train can provide the required capability.

Concurrent failure of two EVS trains would result in the loss-of-functional capability; therefore, LCO 3.0.3 must be immediately entered.

B.1

With one EVS train inoperable, verify that the Required Actions have been initiated for those supported systems declared inoperable by the support EVS train within a Completion Time of [ ] hours.

The [ ]-hour Completion Time is defined as the most limiting time 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 inoperability of EVS trains 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 B of this LCO.]

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

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BASES (continued)

ACTIONS (continued)

C.1

With one EVS train inoperable, and one or more required support or supported features inoperable associated with the other redundant EVS train, a loss-of-function capability results, and LCO 3.0.3 must be entered immediately. If the support or supported features' LCOs take into consideration the loss of function situation, however, then LCO 3.0.3 may not need to be entered.

D.1 and D.2

If the EVS train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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 3.7.14.1

This SR verifies that a train 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. Since the environment and normal operating conditions on this system are not severe, testing each train once a month provides an adequate check on this system. Monthly heater operations dry out any moisture that may have accumulated in the charcoal from 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 equipment and the two-train redundancy available.

SR 3.7.14.2

The Ventilation Filter Testing Program (VFTP) encompasses all the EVS filter tests in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.14.3

This SR demonstrates that, on an actual or simulated actuation signal, each EVS train starts and operates. The 18-month Frequency is consistent with that specified in Regulatory Guide 1.52 (Ref. 4).

SR 3.7.14.4

This SR demonstrates the integrity of the negative pressure boundary area. The ability of the EVS to maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper functioning of the EVS. During the post-accident mode of operation, the EVS is designed to maintain a slight negative pressure in the negative pressure boundary area with respect to adjacent areas to prevent unfiltered LEAKAGE. The EVS is designed to maintain this negative pressure at a flow rate of [3000] cfm from the negative pressure boundary area. The Frequency of 18 months is consistent with the guidance provided in NUREG-800, Section 6.5.1 (Ref. 5).

The minimum system flow rate maintains a slight negative pressure in the negative pressure boundary area, and provides sufficient air velocity to transport particulate contaminants, assuming only one operating filter train.

The number of filter elements is selected to limit the flow rate through any individual element to about [1000] ft^3/min. This may vary based on filter housing geometry. The maximum limit ensures that flow through, and pressure drops across, each filter element are not excessive.

The number and depth of the adsorber elements ensures that, at the maximum flow rate, the residence time of the air stream in the charcoal bed achieves the desired adsorption rate. At least a [0.125]-second residence time is necessary for an assumed [99]% efficiency.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

When clean, the filters have a certain pressure drop at the design flow rate. The magnitude of the pressure drop indicates acceptable performance and is based on manufacturers' recommendations for the filter and adsorber elements at the design flow rate. An increase in pressure drop, or decrease in flow indicates that the filter is being loaded or that there are other problems with the system.

This test is conducted with the tests for filter penetration, and thus an 18-month Frequency, consistent with that specified in Regulatory Guide 1.52 (Ref. 4), is used.

SR 3.7.14.5

Operating the bypass damper is necessary to ensure that the system functions properly. The OPERABILITY of the bypass damper is verified if it can be opened. An 18-month Frequency is consistent with that specified in Regulatory Guide 1.52 (Ref. 4).

REFERENCES

1. [Unit Name] FSAR, Section [6.2.3], "[Containment Vessel Air Purification and Cleanup Systems]."

2. [Unit Name] FSAR, Section [9.4.2], "[Auxiliary Building]."

3. [Unit Name] FSAR, Section [15.4.6], "[Major Rupture of Pipes Containing Reactor Coolant Up to and Including Double-Ended Rupture of the Largest Pipe in the Reactor Coolant System (Loss-of-Coolant Accident)]."

4. Regulatory Guide 1.52 (Rev. 02), "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants."

5. NUREG-0800, Section 6.5.1, "Standard Review Plan", Rev. 2, "ESF Atmosphere Cleanup Systems," July 1981.

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BASES (continued)

REFERENCES (continued)	6.	Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone and Population Center Distance."

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B 3.7 PLANT SYSTEMS

B 3.7.15 Fuel Storage Pool Ventilation System (FSPVS)

BASES

BACKGROUND

The FSPVS provides negative pressure in the fuel storage area, and filters airborne radioactive particulates from the area of the fuel pool following a fuel-handling accident. The FSPVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the fuel pool area.

The FSPVS consists of portions of the normal Fuel Handling Area Ventilation System (FHAVS), the station Emergency Ventilation System (EVS), ductwork bypasses, and dampers. The portion of the normal FHAVS used by the FSPVS consists of ducting between the spent-fuel pool and the normal FHAVS exhaust fans or dampers, and redundant radiation detectors installed close to the suction end of the FHAVS exhaust fan ducting. The portion of the EVS used by the FSPVS consists of two independent, redundant trains. Each train consists of a heater, prefilter or demister, high efficiency particulate air (HEPA) filter, activated charcoal adsorber section for removal of gaseous activity (principally iodines), and fan. Ductwork, valves or dampers, and instrumentation also form part of the system, as well as demisters functioning to reduce the relative humidity of the air stream. A second bank of HEPA filters follows the adsorber section to collect carbon fines, and provide backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the analysis, but serves to collect charcoal fines and to back up the upstream HEPA filter should it develop a leak. Two isolation valves are installed in series in the ducting between the FHAVS and the EVS to provide isolation of the EVS from the FHAVS on an Engineered Safety Feature Actuation System (ESFAS). These valves are opened prior to fuel handling operations. The EVS is the subject of LCO 3.7.14, and is fully described in Reference 2. A ductwork bypass with redundant dampers connects the FHAVS to the EVS.

During normal operation, the exhaust from the fuel-handling area is passed through the FHAVS exhaust filter and is discharged through the station vent stack. In the event of a fuel-handling accident, the radiation detectors (one per

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BASES (continued)

BACKGROUND (continued)

EVS train), located at the suction of the FHAVS exhaust-fan ducting, send signals to isolate the FHAVS supply and exhaust fans and ducting, open the redundant dampers in the bypass ducting, and start the EVS fans. The EVS fans pull the air from the fuel-handling area, creating a negative pressure, and discharge the filtered air to the station vent.

The FHAVS is discussed in several sections of the FSAR (Refs. 1, 2, and 3) because it may be used for normal as well as post-accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The FSPVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel-handling accident. The analysis of the fuel-handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged. The analysis of the LOCA assumes that radioactive materials leaked from the Emergency Core Cooling System (ECCS) are filtered and adsorbed by the FSPVS. The DBA analysis of the fuel-handling accident assumes that only one train of the FSPVS is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the remaining one train of this filtration system. The amount of fission products available for release from the fuel-handling building is determined for a fuel-handling accident and for a LOCA. These assumptions and the analysis follow the guidance provided in Regulatory Guide 1.25 (Ref. 6).

The FSPVS satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

Two independent and redundant trains of the FSPVS are required to ensure that at least one is available, assuming a single failure that disables the other train coincident with a loss-of-offsite power. Total system failure could result in the atmospheric release from the fuel-handling area exceeding 10 CFR 100 limits in the event of a fuel-handling accident.

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BASES (continued)

LCO (continued)

The FSPVS is considered OPERABLE when the individual components necessary to control operator exposure in the fuel handling building are OPERABLE in both trains. A train is considered OPERABLE when its associated:

1. Fan is OPERABLE;
2. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration functions;
3. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained;
4. Radiation monitor is OPERABLE; and
5. SRs are met.

[For this facility, the support systems required to be OPERABLE to ensure FSPVS OPERABILITY are as follows:]

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the FSPVS is required to be OPERABLE to provide fission-product removal associated with ECCS leaks due to a loss-of-coolant accident (refer to LCO 3.7.14) for plants that use this system as part of their Emergency Ventilation Systems (EVS).

In MODES 5 and 6, the FSPVS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

During movement of irradiated fuel in the fuel-handling area, the FSPVS is always required to be OPERABLE to alleviate the consequences of a fuel-handling accident.

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BASES (continued)

ACTIONS

A.1

If one FSPVS train is inoperable, the inoperable train must be restored to OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the FSPVS function. The 7-day Completion Time is based on the risk from an event requiring the inoperable FSPVS train, considering that the remaining FSPVS train can provide the required protection.

B.1 and B.2

In MODES 1, 2, 3, or 4, when Required Action A.1 cannot be completed within the required Completion Time, or when both FSPVS trains are INOPERABLE, the plant must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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.

C.1 and C.2

When Required Action A.1 cannot be completed within the required Completion Time during movement of irradiated fuel in the fuel-handling area, the OPERABLE FSPVS train should be started immediately or fuel movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures that would prevent system operation will occur, and that any active failures will be readily detected.

If the system is not placed in operation, this action requires suspension of fuel movement, which precludes a fuel-handling accident. This action does not preclude the movement of fuel to a safe position.

D.1

When two trains of the FSPVS are inoperable during movement of irradiated fuel in the fuel-handling area, action should be taken to place the plant in a condition in which the LCO is not applicable. This LCO involves immediately suspending

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BASES (continued)

ACTIONS (continued)

movement of irradiated fuel in the fuel-handling area. This action does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR demonstrates that a train 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 environment and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system. Monthly heater operation drys out any moisture accumulated in the charcoal from 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-train redundancy available.

SR 3.7.15.2

The Ventilation Filter Testing Program (VFTP) (Technical Specification 5.7.4.p) encompasses all the FSPVS filter tests in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.15.3

This SR demonstrates that on an actual or simulated actuation signal, each FSPVS train starts and operates. The 18-month Frequency is consistent with that specified in Regulatory Guide 1.52 (Ref. 4).

SR 3.7.15.4

This SR demonstrates the integrity of the fuel-handling area. The ability of the fuel-handling area to maintain a

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper function of the FSPVS. During the emergency mode of operation, the FSPVS is designed to maintain a slight negative pressure in the fuel-handling area with respect to adjacent areas, to prevent unfiltered LEAKAGE. The FSPVS is designed to maintain this negative pressure at a flow rate of ≤ [3,000] cfm to the fuel-handling area. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 5).

The minimum system flow rate maintains a negative pressure in the fuel-handling area, and provides sufficient air velocity to transport particulate contaminants, assuming that only one filter train is operating.

The number of filter elements is selected to limit the flow rate, through any individual element to about [1,000] cfm. This may vary based on filter housing geometry. The maximum limit ensures that flow through, and pressure drop across, each filter element is not excessive.

The number and depth of the adsorber elements ensure that at the maximum flow rate, the residence time of the air stream in the charcoal bed achieves the desired adsorption rate. At least a [0.125]-second residence time is necessary for an assumed [99]% efficiency.

When clean, the filters have a certain pressure drop at the design flow rate. The pressure drop indicates acceptable performance, and is based on manufacturers' recommendations for the filter and adsorber elements at the design flow rate. An increase in pressure drop, or decrease in flow indicates that the filter is being loaded or that other problems exist within the system.

This test is conducted with the tests for filter penetration; thus, an 18-month Frequency, consistent with that specified in Regulatory Guide 1.52 (Ref. 4), is used.

SR 3.7.15.5

Operating the bypass damper is necessary to ensure that the system functions properly. The OPERABILITY of the bypass

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

damper is verified if it can be opened. A Frequency of 18 months is specified in Regulatory Guide 1.52 (Ref. 4).

REFERENCES

1. [Unit Name] FSAR, Section [9.4.2], "[Auxiliary Building]."

2. [Unit Name] FSAR, Section [6.2.3], "[Containment Vessel Air Purification and Cleanup Systems]."

3. [Unit Name] FSAR, Section [15.4.7], "[Fuel-Handling Accident]."

4. Regulatory Guide 1.52 (Rev. 02), "Design, Testing, and Maintenance Criteria for Post Accident Engineered Safety Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants."

5. NUREG-0800, Section 6.5.1, "Standard Review Plan," Rev. 2, "ESF Atmosphere Cleanup System."

6. 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."

B 3.7 PLANT SYSTEMS

B 3.7.16 Steam Generator (SG) Level

BASES

BACKGROUND

A principal function of the steam generators is to provide superheated steam at a constant pressure (900 psia) over the power range. Steam generator water inventory is maintained large enough to provide adequate primary-to-secondary heat transfer. Mass inventory and indicated water level in the steam generator increases with load as the length of the four heat transfer regions within the steam generator vary. Inventory is controlled indirectly as a function of power by the feedwater controls in the Integrated Control System.

The minimum steam generator indicated water level of [18] inches ensures that more than just saturated steam exists in the steam generator, and provides margin to the normal low-level control setpoint. At 900 psia, the steam head alone could result in an indicated level on the startup range of approximately [10 to 12] inches of standard H_2O. Accounting for instrument error under normal conditions yields another 5 inches (based on 22% uncertainty of the 250-inch startup-range level indication). The normal low-level control setpoint is [26] inches.

The maximum operating steam generator level is based primarily on preserving the initial condition assumptions for steam generator inventory used in the FSAR steam line break (SLB) analysis. An inventory of 62,600 lb was used in this analysis. The 62,600 lb must not be exceeded due to the concerns of a possible return to criticality because of primary-side cooling following a SLB and the maximum pressure in the reactor building.

For a clean once-through steam generator (OTSG), the mass inventory in a steam generator for operating at 100% power is approximately 44,000 lb.

As a steam generator becomes fouled and the operating level approaches the limit of 96%, the mass inventory in the downcomer region increases approximately 10,000 lb, and adds to the total mass inventory of the steam generator. In matching plant data of startup level versus power, the

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BASES (continued)

BACKGROUND (continued)

VAGEN code determined that fouling of the lower-tube support plates does not significantly change the heat-transfer characteristics of the steam generator. Thus, the steam temperature, or superheat, is not degraded due to the fouling of the tube support plates, and mass inventory changes are mainly due to the added level in the downcomer.

Analytically, increasing the fouling of the steam generator tube surfaces that degrade the heat-transfer capability of the steam generator, increases the mass inventory, and decreases the steam superheat at 100% power (2544 MW). The results were presented as the amount of mass inventory in each steam generator versus operating range level and steam superheat.

The limiting curve, which was determined from several VAGEN code runs at a power level of 100%, conservatively bounds steam generator mass inventory value, when operating at power levels less than 100%.

The points displayed in Figure 3.7.16-1 are the intercept joints of the 57,000 lb mass value, and the operating range and steam superheat values.

The VAGEN analysis also proved that startup and full-range level instruments are inadequate indicators of steam generator mass inventory at high-power levels due to the combination of static- and dynamic-pressure losses. If the water level should rise above the 96% upper limit, the steam superheat would tend to decrease. Normally, a reduction in water level is manually initiated to maintain steam flow through the aspirator port by reducing the power level. Thus, the superheat versus level limitation also tends to assure that, in normal operation, water level will remain clear of the aspirator ports.

Feedwater nozzle flooding would impair feedwater heating, and could result in excessive tube-to-shell temperature differentials, excessive tubesheet temperature differentials, and large variations in pressurizer level.

APPLICABLE SAFETY ANALYSES

The most limiting Design Basis Accident (DBA) that would be affected by steam generator operating level is a steam line

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

failure. This accident is evaluated in Reference 1. The parameter of interest is the mass of water, or inventory, contained in the steam generator due to its role in lowering Reactor Coolant System (RCS) temperature (return to criticality concern), and in raising containment pressure during an SLB accident. A higher inventory causes the effects of the accident to be more severe. The FSAR assumes an inventory of 62,600 lb for the purpose of analyzing this accident, which is conservatively high. Figure 3.7.16-1 is based upon maintaining inventory less than 57,000 lb, which is 10% less than the inventory used in the FSAR accident analysis, and therefore is conservative.

The steam generator level satisfies Criterion 3 of the NRC Interim Policy Statement.

LCO

This LCO is required to preserve the capability of the steam generator to remove heat from the RCS, and to preserve the initial condition assumptions of the accident analyses. Failure to meet the minimum steam generator level LCO requirements could result in the steam generators being unavailable for primary-side heat removal.

Failure to meet the maximum steam generator level LCO requirements can result in additional mass and energy released to containment, and excessive cooling (and related core reactivity effects) following an SLB. In addition, feedwater nozzle flooding would impair feedwater heating, and could result in excessive tube-to-shell temperature differentials and excessive tubesheet differentials.

[For this facility, the following constitutes an OPERABLE steam generator level:]

[For this facility, the following support systems are required to be OPERABLE to ensure steam generator level OPERABILITY:]

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

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BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a minimum steam generator water level of [18] inches is required to ensure that the steam generator is available and, in this aspect, capable of removing RCS decay heat. A maximum steam generator water level is required to preserve the initial condition assumption for steam generator inventory used in the FSAR steam line failure accident analysis.

In MODES 5 and 6, the minimum steam generator level is not required since decay heat will be removed by the decay-heat removal system.

ACTIONS

A.1 and A.2

If the [illegible] level in one or more steam generators is < [18] [illegible], the plant must be placed in a MODE that minimizes the accident risk. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 5 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.

In the event that the required steam generator level channels are found inoperable, the steam generator level is considered to be not within limits, and Required Actions A.1 and A.2 apply.

B.1 and B.2

If the water level in one or more steam generators is ≥ the maximum level in Figure 3.7.16-1, the plant must be placed in a MODE that minimizes the accident risk. This is done by placing the plant in at least MODE 3 within 6 hours, and in MODE 4 within 12 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.

In the event that the required steam generator level channels are found inoperable, the steam generator level is considered to be not within limits and Required Action B.1 and Required Action B.2 apply.

(continued)

BASES (continued)

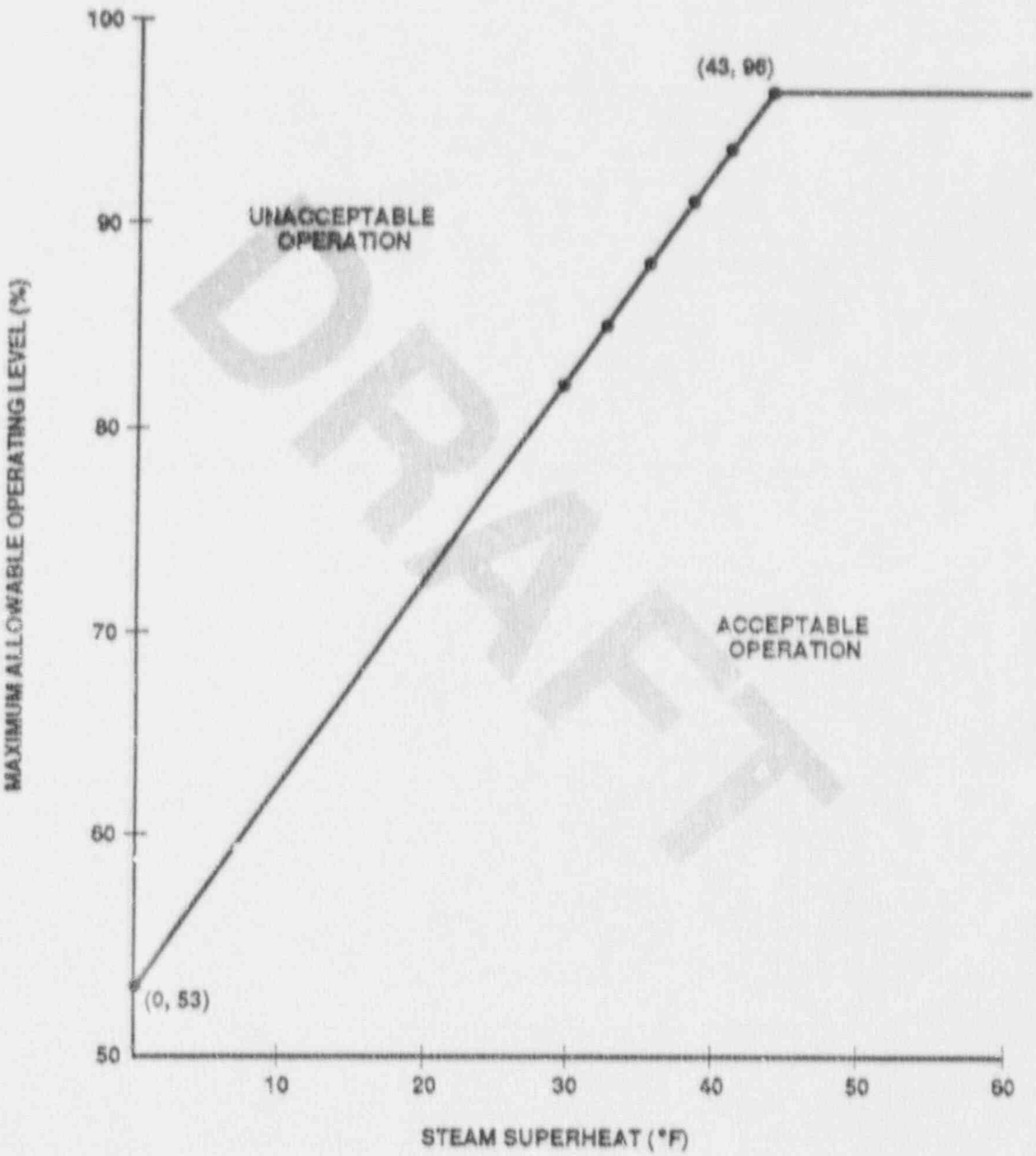

Figure 3.7.16-1

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.7.16.1 This SR verifies the steam generator level to be within acceptable limits. The 12-hour Frequency is adequate because the operator will be aware of plant evolutions that can affect the steam generator level between checks. Furthermore, the 12-hour Frequency is considered adequate in view of other indications, including alarms, available in the control room to alert the operator of steam generator level status.
REFERENCES	1. [Unit Name] FSAR, Section [15.4.4], "[Steam Line Break]."

DRAFT

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.]}

(continued)

(continued)

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

(continued)

(continued)

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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(continued)

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.]

<u>Onsite Sources</u>

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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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:

[ ]

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(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 operability, 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 operable. 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 operability 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 operable. However, when the Specification definition of OPERABILITY is used in place of operability, 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: <u>B.1, B.2.1, and B.2.2</u>}
{VS-CE: <u>B.1, and B.2</u>}

{VS-BW,CE,W:
Condition B is no offsite power to one [division] of the onsite Class 1E Power Distribution System <u>AND</u> 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, <u>OR</u> the turbine-driven auxiliary feedwater pump inoperable.

{VS-W,CE,W:
Note that the <u>OR</u> in Condition B is not an exclusive "or". That is, the <u>OR</u> 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 <u>AND</u> 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 <u>AND</u> 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 malt 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.}

<u>Definition of DX</u>: 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)

ACTIONS (continued)

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 ther may not even be a [Division 3] [automatic sequence 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.

<u>SR 3.8.1.6</u>

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).

<u>SR 3.8.1.7</u>

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 SP 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.

<u>SR 3.8.1.20</u>

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] $\leq$ power factor $\leq$ [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 Guid 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 Surveillances. 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 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.

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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 3.8.1.15

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 SF 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 <u>operability</u> 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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BASES (continued)

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

[illegible]ery-service test is a special test of the battery's [illegible]ility, "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 [illegible] 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

B 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 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 (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 electrical systems, as well as other GDC related to safety-related 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."

(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:]

(continued)

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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(continued)

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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(continued)

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:]

B.1

With one required inverter inoperable AND 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.

C.1 and C.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 3.8.5.1

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 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:]

(continued)

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 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.

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 one 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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(continued)

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 <u>one</u> [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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(continued)

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 consideration 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] [480 V] [480 V] [120 V]	[ESF Bus] [NB01] Load Centers [NG01, NG03] Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D] Distribution Panels [NP01, NP03]	[ESF Bus] [NB02] Load Centers [NG02, NG04] Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D] Distribution Panels [NP02, NP04]	[ESF Bus] [NB03] Motor Control Centers [NG05A, NG05C] Distribution Panels [NP05, NP06]
DC buses	[125 V]	Bus [NK01] from battery [NN11] and charger [NK21] Bus [NK03] from battery [NN13] and charger [NK23] Distribution Panels [NK41, NK43, NK51]	Bus [NK02] from battery [NK12] and charger [NK22] Bus [NK04] from battery [NK14] and charger [NK24] Distribution Panels [NK42, NK44, NK52]	Bus [NK05] from battery [NK15] and charger [NK25] Distribution Panel [NK45]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01] Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN02] from inverter [NN12] connected to bus [NK02] Bus [NN04] from inverter [NN14] connected to bus [NK04]	Bus [NN05] from inverter [NN15] connected to bus [NK05]

* 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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(continued)

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

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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.6 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 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS), the refueling cavity, and the refueling canal during refueling ensures that the reactor remains subcritical during MODE 6 under all conditions. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration counters the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the CORE OPERATING LIMITS REPORT (COLR). Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $K_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical Addition System (CAS) serves as the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling cavity and the refueling canal are then flooded with borated water from the borated water storage tank (BWST) into the open reactor vessel by gravity feeding or by the use of the Decay Heat Removal (DHR) System pumps.

During refueling, the water volumes in the RCS, the refueling cavity, and the refueling canal are contiguous. However, the soluble boron concentration is not necessarily

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BASES (continued)

BACKGROUND (continued)	the same in each volume. If additions of boron are required during refueling, the CAS makes it available through the RCS. The pumping action of the DHR System in the RCS, and the natural circulation due to thermal driving heads in the reactor vessel and the refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The DHR System is in operation during refueling (see LCO 3.9.4 and LCO 3.9.5) to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling cavity, and the refueling canal above the COLR limit.
APPLICABLE SAFETY ANALYSES	During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling). It includes an uncertainty allowance of [ ] ppm. The required boron concentration and the plant refueling procedures that verify the correct fuel-loading plan (including full core mapping) ensure the K_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling. The limiting boron dilution accident occurs in MODE 5 (Ref. 2). A detailed discussion of this event is provided in Bases B 3.1.2, "SHUTDOWN MARGIN - $T_{avg} \leq 200°F$." The RCS boron concentration in MODE 6 satisfies Criterion 2 of the NRC Interim Policy Statement.
LCO	The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling cavity, and the refueling canal while in MODE 6. The boron concentration limit specified in the COLR ensures a core K_{eff} of ≤ 0.95 is

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BASES (continued)

LCO (continued)	maintained during fuel-handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.
APPLICABILITY	This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $K_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1 and LCO 3.1.2, "SHUTDOWN MARGIN," ensure that an adequate amount of negative reactivity is available to shut down the reactor and to maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the plant in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling cavity, or the refueling canal is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude completion of the movement of a component to a safe condition.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated within 15 minutes. The 15-minute Completion Time is allowed for an operator to correctly align and start the required systems.

In determining the required combination of boration flow rate and concentration, there is no unique design basis event that must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the boration is performed at ≥ [ ] gpm of a solution containing [ ] ppm boron or its equivalent.

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BASES (continued)

ACTIONS (continued)	Once boration is initiated, it must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration. In the event that the required boron concentration channels are found inoperable, the boron concentration is considered to be not within limits and Required Actions A.1, A.2, and A.3 apply.
SURVEILLANCE REQUIREMENTS	SR 3.9.1.1 This SR verifies the coolant boron concentrations in the RCS, the refueling cavity, and the refueling canal are within the COLR limit. The boron concentration of the coolant in each volume is determined periodically by chemical analysis. [This facility maintains the following controls to ensure that the likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote:] A minimum Frequency of once every 72 hours is therefore a reasonable interval to verify the boron concentrations of representative samples. The surveillance interval is based on operating experience which has shown 72 hours to be an adequate interval.
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 [ ], "[Accident Analysis]."

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The installed source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas-filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps) with a [5]% instrument accuracy. The detectors also provide continuous visual indication in the control room and an audible alarm to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as by a boron dilution accident or an improperly loaded fuel assembly. The safety analysis of the uncontrolled boron dilution accident is described in Reference 2. The corrective action for such an event is for the operator to close the primary water makeup valve which provides makeup water to the Reactor Coolant System (RCS). The analysis of the uncontrolled boron dilution accident shows that the time for operator corrective action to terminate the event is greater than the 30 minutes required in Reference 3.

The source range neutron flux monitors satisfy Criterion 3 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

This LCO requires two source range neutron flux monitors OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. The OPERABILITY of the monitors is established via a CHANNEL CHECK and CHANNEL FUNCTIONAL TEST. OPERABILITY of the monitors also constitutes a separate continuous visual indication in the control room and an audible alarm in both the control room and the containment for each instrumentation train. The presence of an audible (count rate) signal in the control room and in the containment provides the operators with a method of quickly identifying significant changes in the source range neutron flux level.

[For this facility, the following support systems are required OPERABLE to ensure source range neutron flux monitor OPERABILITY:]

[For this facility, those required support systems which upon their failure do not declare the source range neutron flux monitor inoperable and their justification are as follows:]

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There is no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.9, "Source Range Neutron Flux."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of actions to establish a safe condition.

(continued)

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BASES (continued)

ACTIONS (continued)

A.3

With only one source range neutron flux monitor OPERABLE, action shall be initiated to restore [illegible] inoperable monitor to OPERABLE status within 7 days. [illegible] days is a reasonable time in which corrective actions [illegible] initiated considering the 72-hour boron s[illegible]quency of SR 3.9.1.1, the suspension of C[illegible]IONS per Required Action A.1, and positive reacti[illegible]s per Required A.2 above. Corrective actions, once [illegible] must be continued until the monitor is restored to OPERABLE status.

B.1

With no source range neutron flux mon[illegible]ABLE, actions to restore a monitor to OPERABLE status shall be initiated within 15 minutes. Once initiated, actions shall be continued until a source range neutron flux monitor is restored to OPERABLE status. The 15-minute Completion Time is allowed for an operator to initiate corrective actions.

B.2

With no source range neutron flux monitor OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to verify that the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration. The Frequency of once per 12 hours ensures that unplanned changes in boron concentration would be identified. The 12-hour Frequency is reasonable considering the low probability of a change in core reactivity during this time period.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is the comparison of the indicated parameter values for each of the functions. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.9, "Source Range Neutron Flux."

SR 3.9.2.2

The performance of a CHANNEL FUNCTIONAL TEST provides assurance that the analog process control equipment and trip setpoints are within limits. [For this facility, a CHANNEL FUNCTIONAL TEST constitutes the following:] The 7-day Frequency has been shown through operating experience to be a conservative interval considering operating history data for the setpoint drift, and is further justified because any malfunctions would be deterred during the CHANNEL CHECK which is performed every 12 hours.

REFERENCES

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

   GDC 13, "Instrumentation and Control,"

   GDC 26, "Reactivity Control System Redundancy and Capability,"

   GDC 28, "Reactivity Limits," and

   GDC 29, "Protection Against Anticipated Operational Occurrences."

2. [Unit Name] FSAR, Section [ ], "[Uncontrolled Boron Dilution]."

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BASES (continued)

REFERENCES (continued)

3. NUREG-0800, Standard Review Plan, Section 15.4.6, "Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the RCS."

DRAFT

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, a release of fission-product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, there is no potential for containment pressurization as a result of an accident; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission-product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, the equipment hatch must be held in place by at least [four] bolts. Good engineering practice dictates that the bolts required by this LCO, be approximately equally spaced.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1 through 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY

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BASES (continued)

BACKGROUND (continued)

is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, containment closure is required, therefore the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements on containment penetration closure ensure that a release of fission-product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission-product radioactivity release from containment due to a fuel-handling accident during refueling.

The Containment Purge and Exhaust System includes two subsystems. The normal subsystem includes a [42]-inch purge penetration and a [42]-inch exhaust penetration. The second subsystem, or mini-purge system, includes an [8]-inch purge penetration and an [8]-inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the normal purge and exhaust penetrations are secured in the closed position. The two valves in each of the two mini-purge penetrations can be opened intermittently but are closed automatically by the Engineered Safety Feature Actuation System (ESFAS). Neither of the subsystems is subject to a technical specification in MODE 5.

In MODE 6, large air exchangers are necessary to conduct refueling operations. The normal [42]-inch purge system is used for this purpose, and all four valves are closed by the ESFAS in accordance with LCO 3.3.2.

[The mini-purge system remains operational in MODE 6 and all four valves are also closed by the ESFAS.]

or

[The mini-purge system is not used in MODE 6. All four [8]-inch valves are secured in the closed position.]

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BASES (continued)

BACKGROUND (continued)	The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.
APPLICABLE SAFETY ANALYSES	During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, the most severe radiological consequences result from a fuel-handling accident. The fuel-handling accident is a postulated event which involves damage to irradiated fuel (Ref. 1). Fuel-handling accidents, analyzed in Reference 2, include dropping a single fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.6, "Refueling Canal Water Level," and the minimum decay time of [100] hours prior to CORE ALTERATIONS ensure that the release of fission-product radioactivity, subsequent to a fuel-handling accident, result in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan Section 15.7.4, Rev. 1 (Ref. 2), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. The acceptance limits for [Unit Name] offsite radiation exposure will be 25% of 10 CFR 100 values or the NRC staff-approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). During refueling, the requirements for containment penetrations satisfy Criterion 3 of the NRC Interim Policy Statement.
LCO	This LCO limits the consequences of a fuel-handling accident in containment by limiting the potential escape paths for fission-product radioactivity from containment. The LCO requires any penetration providing direct access from the

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BASES (continued)

LCO (continued)

containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge and exhaust penetrations. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that these penetrations are isolable by the reactor building purge isolation signal. The OPERABILITY requirements for this LCO provide the assurance that the automatic purge and exhaust valve closure times specified in the FSAR can be achieved and therefore meet the assumptions used in the safety analysis to assure releases through the valves are terminated such that radiological doses are within the acceptance limit.

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

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

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment because this is when there is a potential for a fuel-handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1, "Containment." In MODES 5 and 6, when CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment are not being conducted, the potential for a fuel-handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

With the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere not in the required status, including the Containment Purge and Exhaust

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(continued)

BASES (continued)

ACTIONS (continued)

Isolation System not capable of automatic actuation when the purge and exhaust valves are open, the plant must be placed in a condition in which the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of fuel assemblies within containment. Performance of these actions shall not preclude completion of actions to establish a safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This surveillance verifies that each of the containment penetrations required to be in its closed position is in that position. The surveillance on the open purge and exhaust valves will verify that the valves are not blocked from closing. Also the surveillance will verify that each valve operator has motive power which will ensure each valve is capable of being closed by an OPERABLE automatic reactor building purge isolation signal.

The surveillance is performed every 7 days during CORE ALTERATIONS or movement of fuel assemblies within the containment with irradiated fuel in containment. The surveillance interval is selected to be commensurate with the normal duration of time to complete fuel-handling operations. A surveillance before the start of refueling operations will provide two or three surveillance verifications during the applicable period for this LCO. As such, this surveillance ensures that a postulated fuel-handling accident that releases fission-product radioactivity within the containment will not result in a release of fission-product radioactivity to the environment.

SR 3.9.3.2

This surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high-radiation signal. The 18-month Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements. In LCO 3.3.2, "Engineered Safety Features Actuation System Instrumentation," the Containment Purge Isolation Signal System requires a CHANNEL

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

CHECK every 7 days and a CHANNEL FUNCTIONAL TEST every 31 days to ensure the channel OPERABILITY during refueling operations. Every 18 months a CHANNEL CALIBRATION is performed. The system actuation response time is demonstrated every 18 months, during refueling, on a STAGGERED TEST BASIS. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Inspection and Testing Program requirements. These surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel-handling accident to limit a release of fission-product radioactivity from the containment.

REFERENCES

1. [Unit Name] FSAR, Section [ ], "[Design Basis Fuel Handling Accidents]."

2. NUREG-0800, Standard Review Plan, Section 15.7.4, "Radiological Consequences of Fuel Handling Accidents," Rev. 1, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Decay Heat Removal (DHR) and Coolant Circulation—High Water Level

BASES

BACKGROUND

The purposes of the DHR System in MODE 6 are to remove decay heat and sensible heat from the Reactor Coolant System (RCS) as required by GDC 34, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the DHR heat exchanger(s) where the heat is transferred to the Component Cooling Water (CCW) System via the DHR heat exchanger(s). The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the DHR System for normal cooldown or decay-heat removal is manually accomplished from the control room. The heat-removal rate is adjusted by control of the flow of reactor coolant through the DHR heat exchanger(s) and bypassing the heat exchanger(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the DHR system.

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 as a result of a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity, and because of the possible addition of water to the reactor vessel with a lower boron concentration than is required to keep the reactor subcritical. The loss of reactor coolant and the reduction in boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. One train of the DHR System is required to be operational in MODE 6 with the water level $\geq$ 23 ft above the top of the reactor vessel flange to prevent this challenge. The LCO does permit de-energizing the DHR pump for short durations under the condition that the boron concentration is not diluted and the core outlet temperature remains < 200°F.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

This conditional de-energizing of the DHR pump does not result in a challenge to the fission-product barrier.

Although the DHR 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 DHR System is retained as a technical specification.

LCO

Only one DHR loop is required for decay-heat removal in MODE 6 with a water level $\geq$ 23 ft above the top of the reactor vessel flange. Only one DHR loop is required to be OPERABLE because the volume of water above the reactor vessel flange provides backup decay-heat removal capability. At least one DHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature when the core exit thermocouples are not connected.

An OPERABLE DHR loop includes a DHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low-end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

[For this facility, a DHR loop in operation constitutes the following:]

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

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

(continued)

(continued)

BASES (continued)

LCO (continued)

[For this facility, the supported systems impacted by the inoperability of a DHR System and the justification of whether or not each supported system is declared inoperable are as follows:] It should be noted that LCO 3.9.4 may need to be augmented with additional Conditions, if it is determined that the DHR System provides support to other systems included in technical specifications during this MODE of operation.

The LCO is modified by a Note that allows the required operating DHR loop to be removed from service for up to 8 hours in a 24-hour period, provided no operation that would cause dilution of the RCS boron concentration is in progress and core temperature is maintained at ≤ 200°F. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot-leg nozzles and RCS-to-DHR isolation valve testing. During this 8-hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

Upon failure to pass SR 3.9.4.1, SR 3.9.4.3, or SR 3.9.4.4 related to the core outlet temperature, the Note shall be modified to permit only removal of the required DHR loop from service for up to 1 hour per 2-hour period.

APPLICABILITY

One DHR loop must be OPERABLE and in operation in MODE 6 with the water level ≥ 23 ft above the top of the reactor vessel flange to provide decay-heat removal. The 23-foot water level was selected because it corresponds to the 23-foot requirement established for fuel movement in LCO 3.9.6, "Refueling Canal Water Level." Requirements for the DHR System in other MODES are covered by LCOs in Section 3.4, "Reactor Coolant System," and Section 3.5, "Emergency Core Cooling System." DHR loop requirements in MODE 6 when water level is < 23 ft above the top of the reactor vessel flange are located in LCO 3.9.5, "Decay Heat Removal and Coolant Circulation—Low Water Level."

ACTIONS

DHR loop requirements are met by having one DHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

(continued)

(continued)

BASES (continued)

ACTIONS (continued)

A.1

If DHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur through the addition of water with a lower boron concentration than that contained in the RCS. Therefore, actions that reduce boron concentration shall be suspended immediately.

A.2

If DHR loop requirements are not met, actions shall be taken immediately to suspend operations involving an increase in reactor decay-heat load. With no forced circulation cooling, decay-heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay-heat load, such as loading a fuel assembly, is prudent under this condition.

A.3

If DHR loop requirements are not met, actions shall be initiated and continued in order to satisfy DHR loop requirements. With the unit in MODE 6 and the refueling cavity water level $\geq$ 23 ft above the top of the reactor vessel flange, a Completion Time of 15 minutes is allowed for an operator to initiate corrective actions.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This surveillance verifies that core temperature is $\leq$ 200°F and, thus, that core cooling is adequate. The Frequency of 12 hours is sufficient considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the DHR System.

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.4.2

This surveillance verifies that the DHR loop 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 and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the DHR System.

SR 3.9.4.3 and SR 3.9.4.4

These surveillances verify that the instruments that monitor core temperature are OPERABLE. The Frequency is consistent with the Frequency for testing instruments in Section 3.3.

[For this facility, a CHANNEL CHECK and CHANNEL CALIBRATION for core exit thermocouples constitutes the following:]

REFERENCES

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

B 3.9 REFUELING OPERATIONS

B 3.9.5 Decay Heat Removal (DHR) and Coolant Circulation—Low Water Level

BASES

BACKGROUND

The purposes of the DHR System in MODE 6 are to remove decay heat and sensible heat from the Reactor Coolant System (RCS) as required by GDC 34, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the DHR heat exchanger(s) where the heat is transferred to the Component Cooling Water (CCW) System via the DHR heat exchanger. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the DHR System for normal cooldown/decay-heat removal is manually accomplished from the control room. The heat-removal rate is adjusted by control of the flow of reactor coolant through the DHR heat exchanger(s) and bypassing the heat exchanger(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the DHR System.

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 resulting loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity, and because of the possible addition of water to the reactor vessel with a lower boron concentration than is required to keep the reactor subcritical. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission-product barrier. Two trains of the DHR System are required to be OPERABLE, and one is required to be in operation, to prevent this challenge.

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BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

Although the DHR 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 DHR System is retained as a technical specification.

LCO

In MODE 6 with the water level < 23 ft above the top of the reactor vessel flange, both DHR loops must be OPERABLE. Additionally, one DHR loop must be in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature when the core exit thermocouples are not connected.

An OPERABLE DHR loop consists of a DHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low-end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

[For this facility, a DHR loop in operation constitutes the following:]

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

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

[For this facility, the supported systems impacted by the inoperability of a DHR System and the justification of whether or not each supported system is declared inoperable are as follows:] It should be noted that LCO 3.9.5 may need to be augmented with additional Conditions, if it is determined that the DHR System provides support to other systems included in technical specifications during this MODE of operation.

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BASES (continued)

APPLICABILITY

Two DHR loops are required to be OPERABLE, and one in operation in MODE 6 when the water level is < 23 ft above the top of the reactor vessel flange to provide decay-heat removal. Requirements for the DHR System in other MODES are covered by LCOs in Section 3.4, "Reactor Coolant System," and Section 3.5, "Emergency Core Cooling System." DHR loop requirements in MODE 6 when the water level is ≥ 23 ft above the top of the reactor vessel flange are located in LCO 3.9.4, "Decay Heat Removal and Coolant Circulation—High Water Level."

ACTIONS

A.1 and A.2

If one DHR loop is inoperable or not in operation, actions shall be initiated and continued until the DHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange while maintaining the correct boron concentration. When the water level is established at ≥ 23 ft above the reactor vessel flange, the Applicability will change to that of LCO 3.9.4, "Decay Heat Removal and Coolant Circulation—High Water Level," and only one DHR loop is required to be OPERABLE and in operation. A Completion Time of 15 minutes is allowed for an operator to initiate corrective actions.

B.1

If no DHR loop is OPERABLE or in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentration can occur by adding water with a lower boron concentration than that contained in the RCS. Therefore, actions that reduce boron concentration shall be suspended immediately.

B.2

If no DHR loop is OPERABLE or in operation, actions shall be initiated immediately and continued without interruption to restore one DHR loop to OPERABLE status and operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE DHR loops and one operating DHR loop should be accomplished expeditiously.

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BASES (continued)

ACTIONS (continued)

If no DHR loop is 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 the reactor vessel flange while maintaining the correct boron concentration. 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. This includes decay-heat removal using the charging or safety injection pumps through the Chemical and Volume Control System (CVCS) with consideration for the boron concentration. The method used to remove decay heat should be the most prudent as well as the safest choice, based upon plant conditions. The choice could be different if the reactor vessel head is in place rather than removed.

In addition to Actions B.1 and B.2, procedures and administrative controls as recommended by Generic Letter No. 88-17, "Loss of Decay Heat Removal," assure additional actions to mitigate the consequences of loss of decay heat removal. The attachment to Generic Letter No. 88-17 includes recommended expeditious actions such as procedures and administrative controls. Procedures and administrative controls reasonably assure that containment closure will be achieved prior to the time at which core uncovery could result from a loss of DHR coupled with an inability to initiate alternate cooling, or addition of water to the RCS inventory. An additional recommendation is the provision of at least two available or OPERABLE means of adding inventory to the RCS in addition to pumps that are a part of the normal DHR systems. Procedures for use of these systems during loss of DHR events should also be provided.

Enclosure 2 to Generic Letter 88-17, "Guidance for Meeting Generic Letter 88-17," describes recommended programmed enhancements to be completed in a longer term than the expeditious actions and includes a discussion of potential future effects on technical specifications.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This surveillance verifies that one DHR loop is OPERABLE, in operation, and circulating reactor coolant. The flow rate

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

is determined by the flow rate necessary to provide efficient decay-heat removal capability and to prevent thermal and boron stratification in the core. In addition, this surveillance verifies that the other DHR loop is OPERABLE.

In addition, during operation of the DHR loop with the water level in the vicinity of the reactor vessel nozzles, the DHR loop flow-rate determination must also consider the DHR pump suction requirement. The Frequency of 12 hours is sufficient considering the flow, temperature, pump control, and alarm indications available to the operator to monitor the DHR System in the control room.

REFERENCES

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

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Canal 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 sufficient water level in the containment, the refueling cavity, the refueling canal, the fuel-transfer canal, and the 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 the refueling canal is an initial condition design parameter in the analysis of the fuel-handling accident in containment postulated by NRC Regulatory 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). The fuel-handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft, and a minimum decay time of 72 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 offsite doses are maintained within allowable limits (Ref. 4). "Refueling Canal Water Level" satisfies Criterion 2 of the NRC Interim Policy Statement.

(continued)

BASES (continued)

LCO

A minimum refueling cavity water level of 23 ft above the irradiated fuel is required to ensure that the radiological consequences of a postulated fuel-handling accident inside containment are within acceptable limits as provided by the guidance of Reference 3.

[For this facility, the following support systems are required OPERABLE to ensure refueling canal water level OPERABILITY:]

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

APPLICABILITY

Within the containment, LCO 3.9.6, "Refueling Canal Water Level," is applicable when moving fuel assemblies in the presence of irradiated fuel assemblies. 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 in Containment, 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 pool are covered by LCO 3.7.10, "Fuel Storage Pool Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel 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.

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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel 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 reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a postulated fuel-handling accident inside 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 of 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(a), "Radiation Dose Standards for Individuals in Restricted Areas."

APPENDIX A

Acronyms

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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)

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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APPENDIX A (continued)

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

(continued)

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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	[illegible] Cl[illegible] 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	minimum 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

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APPENDIX A (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	[illegible] 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

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(continued)

RPIS	Rod Position Information System
RPS	Reactor Protection System
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

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APPENDIX A (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	traversing 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 Babcock and Wilcox Owners Group. 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 - 3.9 of the new STS.

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