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B 3.7 PLANT SYSTEMS (continued)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

UFSAR, Appendix 3D.1.6 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during any combination of normal operation, including the effects of anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (95/95 DNB criterion) that DNB will not occur and by requiring that the fuel centerline temperature stays below the melting temperature.

The restrictions of these SLs prevent overheating of the fuel and cladding and possible cladding perforation that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding-water (zirconium-water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The 95 percent confidence level that DNB will not occur is preserved by ensuring that the DNBR remains greater than the DNBR design limit based on the applicable critical heat flux (CHF) correlation for the core design. In the development of the applicable DNBR design limit (Ref. 2), uncertainties in the core state variables, power peaking factors,

BASES

BACKGROUND (continued)

manufacturing-related parameters, and the CHF correlation are statistically combined to determine a statistical DNBR design limit. This statistical design limit protects the respective CHF design limit. Additional retained thermal margin may also be applied to the statistical DNBR design limit to yield a higher thermal design limit for use in establishing DNB-based core safety and operating limits. In all cases, application of statistical DNB design methods preserves a 95 percent probability at a 95 percent confidence level that DNB will not occur.

DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB using CHF correlations. The local DNB heat flux ratio, DNBR, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The BWC and BHTP CHF correlations have been developed to predict DNB for axially uniform and non-uniform heat flux distributions. The BWC correlation (Ref. 2) applies to Mark-B fuel with zircaloy or M5 spacer grids. The BHTP correlation (Ref. 2) applies to the Mark-B-HTP fuel. The minimum value of the DNBR during steady state operation, normal operational transients, and anticipated transients is limited to 1.18 (BWC) and 1.132 (BHTP). The value corresponds to a 95 percent probability at a 95 percent confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The proper functioning of the Reactor Protection System (RPS) prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience fuel centerline melting.

The RPS setpoints, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Automatic enforcement of these reactor core SLs is provided by the following:

a. RC High Temperature trip;

b. RC Low Pressure trip;

c. High Flux trip;

d. RC Pressure-Temperature trip;

e. High Flux/Number of Reactor Coolant Pumps on trip; and

f. Flux - ΔFlux - Flow trip.

These reactor core SLs represent a design requirement for establishing the RPS trip setpoints identified previously.

SAFETY LIMITS

SL 2.1.1.1 and SL 2.1.1.2 ensure that the minimum DNBR is not less than the safety analyses limit and that fuel centerline temperature stays below the melting point, or the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or the exit quality is within the limits defined by the DNBR correlation. In addition, SR 2.1.1.2 shows the pressure/temperature operating region that keeps the reactor from reaching an SL when operating up to design power.

The curve of Figure 2.1.1-1 is the most restrictive of all possible reactor coolant pump-maximum THERMAL POWER combinations. This curve is based on the design hot channel factors with potential fuel densification and fuel rod bowing effects.

The fuel centerline melt and DNBR fuel design limits are not directly monitored by installed plant instrumentation. Instead, monitoring the process variable AXIAL POWER IMBALANCE ensures that the core operates within the fuel design criteria. With AXIAL POWER IMBALANCE within the protective limits, fuel centerline temperature and DNBR are also within limits. Therefore, the Safety Limit is specified to be the AXIAL POWER IMBALANCE protective limits shown in the COLR.

The AXIAL POWER IMBALANCE protective limits are preserved by their corresponding RPS Allowable Values in LCO 3.3.1, as specified in the COLR. The Allowable Values are derived by adjusting the measurement system independent AXIAL POWER IMBALANCE protective limit given in the COLR to allow for measurement system observability and instrumentation errors. Instrument errors not included in establishing the Allowable Values are included in establishing the Trip Setpoints as

BASES

SAFETY LIMITS (continued)

described in the Background section of LCO 3.3.1 Bases. The AXIAL POWER IMBALANCE protective limits are separate and distinct from the AXIAL POWER IMBALANCE operating limits defined by LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits." The AXIAL POWER IMBALANCE operating limits in LCO 3.2.3, also specified in the COLR, preserve initial conditions of the safety analyses but are not reactor core SLs.

APPLICABILITY

SL 2.1.1.1 and SL 2.1.1.2 only apply in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The automatic protection actions serve to prevent RCS heatup to reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Allowable Values for the RPS Instrumentation Functions are specified in LCO 3.3.1.

In MODES 3, 4, 5, and 6, Applicability is not required, since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation actions are applicable to the reactor core SLs.

2.2.1 and 2.2.2

If SL 2.1.1.1 or SL 2.1.1.2 is violated, the requirement to go to MODE 3 places the plant in a MODE in which these SLs are not applicable. This ensures compliance with 10 CFR 50.36 (c)(1)(i)(A), which requires a shutdown when safety limits are violated. In addition, if SL 2.1.1.2 is violated, the requirement is to restore the RCS pressure and temperature to within limits. Exceeding SL 2.1.1.2 may cause immediate fuel failure; therefore it is necessary to restore RCS pressure and temperature to within limits.

The allowed Completion Time of 1 hour recognizes the importance of bringing the plant to a MODE of operation where these SLs are not applicable and reduces the probability of fuel damage.

REFERENCES

1. UFSAR, Appendix 3D.1.6, Criterion 10 – Reactor Design.

2. BAW-10179P-A, "Safety Criteria and Methodology for Acceptable Cycle Reload Analyses" (revision specified in Specification 5.6.3).

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

According to UFSAR, Appendix 3D.1.11 (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation nor during anticipated operational occurrences (AOOs). UFSAR, Appendix 3D.1.24 (Ref. 1), specifies that reactivity accidents including rod ejection do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2500 psig. During normal operation and AOOs, the RCS pressure is kept from exceeding the design pressure by more than 10% in order to remain in accordance with the design codes (Refs. 2 and 3). Hence, the safety limit is 2750 psig. To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure prior to initial operation, according to the design code requirements. A system leakage test at normal operating pressure is required near the end of each refueling outage. Pressure tests are performed per ASME Code, Section XI (Ref. 4) following repair or replacement activities.

APPLICABLE SAFETY ANALYSES

The RCS pressurizer code safety valves, operating in conjunction with the Reactor Protection System trip settings, ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer code safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that is most influential for establishing the required relief capacity, and hence the valve size requirements and lift settings, is a rod withdrawal from a subcritical condition. During the transient, the analysis assumes full reactor coolant flow but no heat transfer out of the primary system to maximize system conditions.

The overpressure protection analyses (Ref. 5) and the safety analyses (Ref. 6) are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer pilot operated relief valve (PORV);

b. Make-up flow;

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Primary to secondary heat transfer; and

d. Pressurizer spray valve.

SAFETY LIMIT

The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under ANSI USAS, Section B31.7 (Ref. 3), is 110% of design pressure. Therefore, the SL on maximum allowable RCS pressure is 2750 psig.

Overpressurization of the RCS can result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 7).

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES during overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

SAFETY LIMIT VIOLATIONS

The following SL violation actions are applicable to the RCS pressure SL.

2.2.3

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour. Placing the unit in MODE 3 ensures compliance with 10 CFR 50.36 (c)(1)(i)(A), which requires a shutdown when safety limits are violated.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 7).

The allowed Completion Time of 1 hour is based on the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

BASES

SAFETY LIMIT VIOLATIONS

2.2.4

If the RCS pressure SL is violated in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes.

Violating the RCS pressure SL in MODE 3, 4, or 5 is potentially more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. This action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. UFSAR, Appendix 3D.1.11, Criterion 15 – Reactor Coolant System Design, and Appendix 3D.1.24, Criterion 28 – Reactivity Limits.
2. ASME Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ANSI USAS B31.7 Draft, Nuclear Power Piping, February 1968 with Errata dated June 1968.
4. ASME Boiler and Pressure Vessel Code, Section XI.
5. BAW-10043, May 1972.
6. UFSAR, Section 15.
7. 10 CFR 100.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified. There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation. Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

BASES

LCO 3.0.2 (continued)

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. Reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

BASES

LCO 3.0.3 (continued)

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, "Completion Times."

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met;

b. A Condition exists for which the Required Actions have now been performed; or

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching

BASES

LCO 3.0.3 (continued)

MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.14, "Spent Fuel Pool Water Level." LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in spent fuel pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, 3, or 4, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.14 to "Suspend movement of irradiated fuel assemblies in spent fuel pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (i.e., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

BASES

LCO 3.0.4 (continued)

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

BASES

LCO 3.0.4 (continued)

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Containment Air Temperature, Containment Pressure, and Moderator Temperature Coefficient), and may be applied to other Specifications based on NRC plant specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

BASES

LCO 3.0.4 (continued)

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate either:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

BASES

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported systems' Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.14, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

One aspect of the SFDP is the provision for cross train checks. The SFDP requires performance of cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems. The cross train check verifies that the supported systems of the remaining OPERABLE support systems are

BASES

LCO 3.0.6 (continued)

OPERABLE, thereby ensuring safety function is retained. A loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1);

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2); or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

<u>EXAMPLE B 3.0.6-1</u> (Refer to Figure B 3.0.1)

If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

<u>EXAMPLE B 3.0.6-2</u> (Refer to Figure B 3.0.1)

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

<u>EXAMPLE B 3.0.6-3</u> (Refer to Figure B 3.0.1)

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10, and 11.

If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

BASES

LCO 3.0.6 (continued)

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately address the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs 3.1.8 and 3.1.9 allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated

BASES

LCO 3.0.8 (continued)

support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

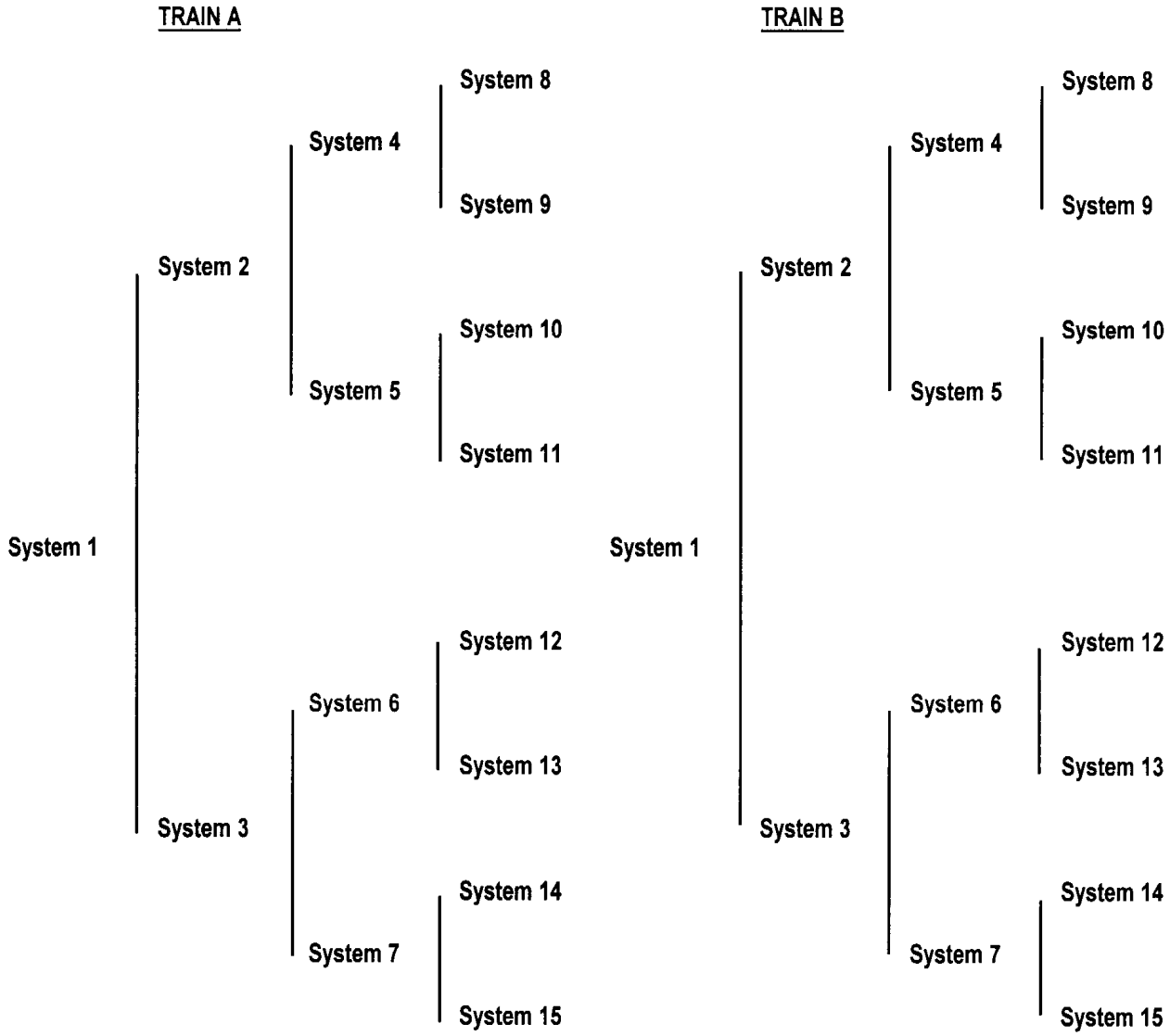

Figure B 3.0-1
Configuration of Trains and Systems

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs	SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
SR 3.0.1	SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps. Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when: a. The systems or components are known to be inoperable, although still meeting the SRs; or b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances. Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Test Exception LCO are only applicable when the Test Exception LCO is used as an allowable exception to the requirements of a Specification. Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR.

BASES

SR 3.0.1 (continued)

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Auxiliary feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures > 800 psi. However, if other appropriate testing is satisfactorily completed, the AFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the AFW pump testing.

b. Main steam safety valve (MSSV) lift setpoint verification performed in-situ requires hot conditions. Provided other appropriate ANSI/ASME OM Code test requirements are satisfactorily completed, startup can proceed and MODE 3 entered with the MSSVs considered OPERABLE. This allows operation to reach the necessary conditions to perform the in-situ lift setpoint verification.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per ..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides an adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

BASES

SR 3.0.3 (continued)

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may

BASES

SR 3.0.3 (continued)

use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to a Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the

BASES

SR 3.0.4 (continued)

requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, "Frequency."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

Two independent reactivity control systems of different design principles are provided. The Control Rod Drive System utilizes control rods and is capable of reliably controlling the rate of reactivity changes and ensures that, under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified fuel design limits are not exceeded. The Makeup and Purification System is capable of controlling the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) to ensure that acceptable fuel design limits are not exceeded. The Makeup and Purification System has the ability to initiate and maintain the cold shutdown condition in the reactor (Ref. 1). SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). The SDM defines the degree of subcriticality that would be obtained immediately following the insertion of all safety and regulating rods, assuming the single CONTROL ROD assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The CONTROL RODS can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the CONTROL RODS, together with the Chemical Addition System and Makeup and Purification System, provide SDM during power operation. The CONTROL RODS are capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The Chemical Addition System and Makeup and Purification System maintain the SDM as the temperature of the reactor coolant is decreased. The Chemical Addition System and Makeup and Purification System are not Technical Specification required systems, but are utilized to support the SDM requirements in MODES 3, 4, and 5.

The Chemical Addition System and Makeup and Purification System can compensate for fuel depletion, during operation and all xenon burnout reactivity changes, and maintain the reactor subcritical under cold conditions. During MODES 1 and 2, SDM control is ensured by operating with the safety rods fully withdrawn (LCO 3.1.5, "Safety Rod Insertion Limits") and the regulating rods within the limits of

BACKGROUND (continued)

LCO 3.2.1, "Regulating Rod Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration. By maintaining the steam generator levels within the maximum level limits of LCO 3.7.18, “Steam Generator Level", in conjunction with establishing the appropriate SDM required for MODE 3, as discussed below, it is assured that the reactor will remain subcritical in the event of a Main Steam Line Break in MODE 3 (Ref. 4).

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in the safety analysis. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with assumption of the highest worth rod stuck out following a reactor trip.

The acceptance criteria for SDM requirements are that specified acceptable fuel design limits are maintained. The SDM requirements must ensure that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable with acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a main steam line break (MSLB), as described in the accident analysis (Ref. 2).

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from a subcritical or low power condition;

c. Startup of an inactive reactor coolant pump;

d. Rod ejection; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. Return to criticality if an MSLB occurs when steam generator level is within the limits of LCO 3.7.18 when in MODE 3. An MSLB with increased inventory in the steam generators results in rapid overcooling of the RCS, thereby adding positive reactivity to the reactor. In MODE 3, at the maximum SG levels allowed by LCO 3.7.18, an increased boron concentration is required to establish the SDM that is necessary to compensate for the cooldown that would result from a MSLB. By maintaining the Steam Generator (SG) levels within the MODE 3 LCO 3.7.18 limits, in conjunction with establishing the required SDM, it is ensured that the reactor will not attain criticality during any postulated MODE 3 MSLB. The increased boron concentration must be established prior to increasing the SG level above the Low Level Limit setpoint (Ref. 4).

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Shutdown boron concentration requirements assume the highest worth rod is stuck in the fully withdrawn position to account for a postulated inoperable or untrippable rod prior to reactor shutdown.

SDM is a core design condition that can be ensured through CONTROL ROD positioning (regulating and shutdown groups) and through the soluble boron concentration.

The MSLB (Ref. 2) accident is the most limiting analysis that establishes the SDM value of the LCO.

For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100 limits (Ref. 3).

To limit the potential heat removal associated with an MSLB accident, the maximum steam generator level is controlled by LCO 3.7.18. Maintaining the steam generator level within the limits of LCO 3.7.18, in conjunction with establishing the required SDM, as presented above in APPLICABLE SAFETY ANALYSES, item e, will ensure the core will remain subcritical following an MSLB accident.

APPLICABILITY

In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5 and LCO 3.2.1. In MODE 3, the SDM requirements presented above in APPLICABLE SAFETY ANALYSES, item e, are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analysis. In MODES 4 and 5, there is no need to limit the steam generator inventory, and the SDM requirements of this LCO are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analysis discussed above. In MODE 6, the

BASES

APPLICABILITY (continued)

shutdown reactivity requirements are given in LCO 3.9.1, “Boron Concentration.”

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met. If the SDM limit is not met due to high steam generator level, RCS boration must be continued until the SDM for an RCS average temperature of < 280°F is achieved.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid addition tanks or the borated water storage tank. The operator should borate with the best source available for the plant conditions.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

The SDM is verified by performing a reactivity balance calculation, considering, but not limited to, the listed reactivity effects:

a. RCS boron concentration;

b. CONTROL ROD position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.1.1 (continued)

The Frequency of 24 hours is based on the generally slow change in required boron concentration, and also allows sufficient time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. UFSAR, Appendix 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability.

2. UFSAR, Section 15.

3. 10 CFR 100, "Reactor Site Criteria."

4. NRC Safety Evaluation for Technical Specification Amendment 192, NRC Letter, Log No. 4424, dated October 7, 1994.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Balance

BASES

BACKGROUND

Two independent reactivity control systems of different design principles are provided. The Control Rod Drive System utilizes control rods and is capable of reliably controlling the rate of reactivity changes and ensures that, under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified fuel design limits are not exceeded. The Makeup and Purification System is capable of controlling the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) to ensure that acceptable fuel design limits are not exceeded. The Makeup and Purification System has the ability to initiate and maintain the cold shutdown condition in the reactor (Ref. 1). Therefore, the reactivity balance is used as a measure of the predicted versus measured core reactivity during startup and power operation. The periodic confirmation of core reactivity is necessary to ensure that safety analyses of design basis transients and accidents remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, CONTROL ROD, or burnable poison worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity. These could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers, producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed, (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations, and that the calculational models used to generate the safety analysis are adequate.

BASES

BACKGROUND (continued)

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel remaining from the previous cycle provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), CONTROL RODS, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are the establishment of the reactivity balance limit to ensure that plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as CONTROL ROD withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes which have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the

BASES

APPLICABLE SAFETY ANALYSES (continued)

calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve, which is developed during fuel depletion, may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the CONTROL RODS in their normal positions for power operation. The normalization is performed at BOC conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated, as core conditions change during the cycle.

Reactivity balance satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled, once the core design is fixed. During operation, therefore, the conditions of the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the Design Basis Accident (DBA) and transient analyses are no longer valid, or that the uncertainties in the nuclear design methodology are larger than expected. A limit on the reactivity of ± 1% $\Delta k/k$ has been established, based on engineering judgment. A ± 1% $\Delta k/k$ deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

BASES

APPLICABILITY

In MODES 1 and 2 during fuel cycle operation with $k_{eff} \geq 1$, the limits on core reactivity must be maintained because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed.

This Specification does not apply in MODES 3, 4, and 5, because the reactor is shutdown and changes to core reactivity due to fuel depletion cannot occur.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Refueling Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis, and an SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement or CONTROL ROD replacement or shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized, and power operation may continue. If operational restrictions or additional surveillance requirements are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

BASES

ACTIONS

A.1 and A.2 (continued

The required Completion Time of 7 days is adequate for preparing operating restrictions or surveillances that may be required to allow continued reactor operation.

B.1

If any Required Action and associated Completion Time cannot be met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then boration required by Required Action A.1 of LCO 3.1.1 would occur. The allowed Completion Time of 6 hours is reasonable, based on operating experience to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made considering that other core conditions are fixed or stable, including CONTROL ROD and APSR positions, RCS average temperature, THERMAL POWER, fuel burnup based on gross thermal energy generation, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. A Note is included in the SR to indicate that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPD, following the initial 60 EFPD after entering MODE 1 is acceptable, based on the slow rate of core reactivity changes due to fuel depletion and the presence of other indicators (QPT, etc.) for prompt indication of an anomaly. Another Note is included in the SRs to indicate that the performance of the Surveillance is not required for entry into MODE 2.

BASES

REFERENCES

1. UFSAR, Appendices 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability; 3D.1.24, Criterion 28 – Reactivity Limits; and 3D.1.25, Criterion 29 – Protection Against Anticipated Operational Occurrences.

2. UFSAR, Section 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND	According to UFSAR, Appendix 3D.1.7 (Ref. 1), the reactor core and associated coolant systems are designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for rapid increase in reactivity. The overall power coefficient, which is the fractional change in neutron multiplication per unit change in core power level, is negative in the power operating range. The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result. The same characteristic is true when the MTC is positive and coolant temperature decreases occur. MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle (BOC) MTC is less than zero when THERMAL POWER is 95% RTP or greater. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional burnable absorbers to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure the MTC does not exceed the EOC limit.
APPLICABLE SAFETY ANALYSES	Reference 2 contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are initial conditions in the safety analyses, and both values must be bounded. Values used in the analyses consider worst case conditions, such as very large soluble boron concentrations, to ensure the accident results are bounding (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

Accidents that cause core overheating (either decreased heat removal or increased power production) must be evaluated for results when the MTC is positive. Reactivity accidents that cause increased power production include the control rod withdrawal transient from either zero or full THERMAL POWER. The limiting overheating event relative to plant response is based on the maximum difference between core power and steam generator heat removal during a transient. The most limiting event with respect to positive MTC at 0% RTP is a startup accident (Ref. 4). The most limiting event with respect to positive MTC at power is a large break Loss of Coolant Accident (Ref. 5).

Accidents that cause core overcooling must be evaluated for results when the MTC is most negative. The event that produces the most rapid cooldown of the RCS, and is therefore the most limiting event with respect to the negative MTC, is a main steam line break (MSLB) event. Following the reactor trip for the postulated EOC MSLB event, the large moderator temperature reduction, combined with the large negative MTC, may produce reactivity increases that are as much as the shutdown reactivity. When this occurs, a substantial fraction of core power is produced with all control rod assemblies inserted, except the most reactive one. Even if the reactivity increase produces slightly subcritical conditions, a large fraction of core power may be produced through the effects of subcritical neutron multiplication.

MTC values are bounded in reload safety evaluations, assuming steady state conditions at BOC and EOC. A near EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

LCO 3.1.3 requires the MTC to be within specified limits in the COLR to ensure the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the UFSAR accident analysis during operation. The LCO establishes a maximum positive value that can not be exceeded. The limit of +0.9E-4 $\Delta k/k/°F$ on positive MTC, when THERMAL POWER is < 95% RTP, ensures that core overheating accidents will not violate the accident analysis assumptions. The requirement for a negative MTC, when THERMAL POWER is ≥ 95% RTP, ensures that core operation will be stable. The negative MTC limit for EOC specified in the COLR ensures that core overcooling accidents will not violate the accident analysis assumptions.

MTC is a core physics parameter determined by the fuel and fuel cycle design and cannot be easily controlled once the core design is fixed during operation, therefore, the LCO can only be ensured through measurement. The surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated, so that the acceptance criteria are met.

APPLICABILITY

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2, the limits must also be maintained to ensure that startup and subcritical accidents, such as the uncontrolled CONTROL ROD assembly or group withdrawal, will not violate the assumptions of the accident analysis. In MODES 3, 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents (DBAs) using the MTC as an analysis assumption are initiated from these MODES. However, the variation of MTC with temperature in MODES 3, 4, and 5 for DBAs initiated in MODES 1 and 2 is accounted for in the subject accident analysis. The variation of MTC with temperature assumed in the safety analysis, is accepted as valid once the BOC measurement is used for normalization.

ACTIONS

A.1

MTC is a function of the fuel and fuel cycle designs, and cannot be controlled directly once the designs have been implemented in the core. If MTC exceeds its limits, the reactor must be placed in MODE 3. This eliminates the potential for violation of the accident analysis. The associated Completion Time of 6 hours is reasonable, considering the probability of an accident occurring during the time period that would require an MTC value within the LCO limits, for reaching MODE 3 conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

The following two SRs for measurement of the MTC at the beginning and end of each fuel cycle provide for confirmation of the limiting MTC values. The MTC changes slowly from most positive (least negative) to most negative value during fuel cycle operation, as the RCS boron concentration is reduced with fuel depletion.

SR 3.1.3.1

The requirement for measurement, prior to initial operation above 5% RTP, satisfies the confirmatory check on the most positive (least negative) MTC value.

SR 3.1.3.2

The requirement for measurement, within 7 effective full power days (EFPD) after reaching an equilibrium boron concentration of 300 ppm for RTP, satisfies the confirmatory check on the lower (most negative or least positive) MTC value. The measurement is performed at any THERMAL POWER equivalent to an RCS boron concentration of 300 ppm (for steady state operation at RTP with all CONTROL RODS fully withdrawn) so that the projected EOC MTC may be evaluated before the reactor actually reaches the EOC condition. MTC values are extrapolated and compensated to permit direct comparison to the specified MTC limits.

The SR is modified by a Note. The Note indicates that SR 3.1.3.2 may be repeated, and shutdown must occur, prior to exceeding the minimum allowable boron concentration at which MTC is projected to exceed the lower limit. The minimum allowable boron concentration is obtained from the EOC MTC versus boron concentration slope with appropriate conservatisms. Thus, the projected EOC MTC is evaluated before the lower limit is actually reached.

REFERENCES

1. UFSAR, Appendix 3.D.1.7, Criterion 11 – Reactor Inherent Protection.
2. UFSAR, Section 15.
3. UFSAR, Appendix 4B.
4. UFSAR, Section 15.2.1.
5. UFSAR, Section 15.4.6.8.2.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 CONTROL ROD Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the CONTROL RODS (safety rods and regulating rods) is an initial condition assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial condition assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these design requirements are UFSAR, Appendices 3D.1.6, 3D.1.21, 3D.1.22, 3D.1.23, and 3D.1.24 (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a CONTROL ROD to become inoperable or to become misaligned from its group. CONTROL ROD inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, CONTROL ROD alignment and OPERABILITY are related to core operation within design power peaking limits and the core design requirement of a minimum SDM.

Limits on CONTROL ROD alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

CONTROL RODS are moved by their CONTROL ROD drive mechanisms (CRDMs). Each CRDM moves its rod 3/4 inch for one revolution of the roller nut assembly around the leadscrew, but at varying rates depending on the signal output from the Control Rod Drive Control System (CRDCS).

The CONTROL RODS are arranged into rod groups that are radially symmetric. Therefore, movement of the CONTROL RODS does not introduce radial asymmetries in the core power distribution. The safety rods and the regulating rods provide required reactivity worth for immediate reactor shutdown upon a reactor trip. The regulating rods provide reactivity (power level) control during normal operation and transients, and their movement is normally governed by the control system in automatic.

BASES

BACKGROUND (continued)

The position of safety rods and regulating rods is indicated by two separate and independent systems, which are the relative position indicator and the absolute position indicator (see LCO 3.1.7, "Position Indicator Channels").

The Relative Position Indication (RPI) is determined in the CRDCS controller by calculating the individual rod position based on CRDM motor power supply SCR gating command pulses. Individual rods in a group all receive the same signal to move; therefore, the counters for all rods in a group should indicate the same position. The Relative Position Indicator System is considered highly precise (one rotor rotation results in 3/4 inch leadscrew and rod motion). If a rod does not move for each demand pulse, the CRDCS controller will still calculate the rod position change based on the SCR gating commands for rod motion and incorrectly reflect the position of the rod.

The Absolute Position Indicator System provides a highly accurate indication of actual CONTROL ROD position, but at a lower precision than relative position indicators. This system is based on inductive analog signals from a series of reed switches spaced along a tube with a center to center distance of 4 inches.

APPLICABLE SAFETY ANALYSES

CONTROL ROD misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing CONTROL ROD misalignment are:

a. THERMAL POWER shall not exceed 110% of 2817 MWt; and

b. Reactor Coolant System (RCS) pressure shall not exceed code pressure limit.

Two types of misalignment are distinguished. During movement of a CONTROL ROD group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs when one rod drops partially or fully into the reactor core. This event causes an initial power reduction followed by a return towards the original power due to positive reactivity feedback from the negative moderator temperature coefficient. Increased peaking during the power increase may result in excessive local linear heat rates (LHRs).

The CONTROL ROD OPERABILITY requirement is satisfied provided the rod will insert within the required rod drop time assumed in the safety analysis (Ref. 4).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CONTROL ROD group alignment limits and OPERABILITY requirements satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on CONTROL ROD group alignment, safety rod insertion, and APSR alignment, together with the limits on regulating rod insertion, APSR insertion, AXIAL POWER IMBALANCE, and QPT, ensure the reactor will operate within the fuel design criteria. The Required Actions in these LCOs ensure that deviations from the alignment limits will either be corrected or that THERMAL POWER will be adjusted, so that excessive local LHRs will not occur and the requirements on SDM and ejected rod worth are preserved.

The requirements on rod OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The rod OPERABILITY requirements (i.e., trippability) are separate from the alignment requirements. The rod OPERABILITY requirement is satisfied provided the rod will insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move a rod but that do not impact trippability, do not result in rod inoperability.

The limit for individual CONTROL ROD misalignment is 6.5% (9 inches) deviation from the group average position. This value is established, based on the distance between reed switches, with additional allowances for uncertainty in the absolute position indicator circuit, DCRDCS controller and the DCRDCS controller asymmetric alarm or fault monitor function. The position of a misaligned rod is not included in the calculation of the rod group average position.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDM or ejected rod worth, all of which may constitute initial conditions inconsistent with the safety analysis.

APPLICABILITY

The requirements on CONTROL ROD OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the CONTROL RODS are typically bottomed, and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the safety and regulating rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5, and

BASES

APPLICABILITY (continued)

LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1

When a CONTROL ROD is re-misaligned, alignment of the CONTROL ROD may be accomplished by either moving the single CONTROL ROD to the group average position, or by moving the remainder of the group to the position of the single misaligned CONTROL ROD. Either action can be used to restore the CONTROL RODS to a radially symmetric pattern. However, this must be done without violating the CONTROL ROD group sequence, overlap, and insertion limits of LCO 3.2.1, "Regulating Rod Insertion Limits." THERMAL POWER must also be restricted, as necessary, to the value allowed by the insertion limits of LCO 3.2.1.

Restoration of the CONTROL ROD is allowed, however compliance with Required Actions A.1.1 through A.6 allows for continued power operation with one CONTROL ROD misaligned from its group average position.

Since the rod may be inserted farther than the group average insertion for a long time, SDM must be evaluated. Ensuring the SDM meets the minimum requirement within 1 hour is adequate to determine that further degradation of the SDM is not occurring.

A.1.2

Restoration of the required SDM requires increasing the RCS boron concentration, since the CONTROL ROD may remain misaligned and not be providing its normal negative reactivity on tripping. RCS boration must occur as described in Bases Section 3.1.1. The required Completion Time of 1 hour to initiate boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time for aligning the required valves and starting the boric acid pumps. Boration will continue until the required SDM is restored.

A.2

Reduction of THERMAL POWER to ≤ 60% ALLOWABLE THERMAL POWER ensures that local LHR increases, due to a misaligned rod, will not cause the core design criteria to be exceeded. The required Completion Time of 2 hours allows the operator sufficient time for reducing THERMAL POWER.

BASES

ACTIONS (continued)

A.3

Reduction of the High Flux trip setpoint to ≤ 70% ALLOWABLE THERMAL POWER, after THERMAL POWER has been reduced to 60% ALLOWABLE THERMAL POWER, maintains both core protection and an operating margin at reduced power similar to that at RTP. The required Completion Time of 10 hours allows the operator 8 additional hours after completion of the THERMAL POWER reduction in Required Action A.2 to adjust the trip setpoint.

A.4

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

A.5

The existing CONTROL ROD configuration must not cause an ejected rod to exceed the limit of 0.65% $\Delta k/k$ at RTP or 1.00% $\Delta k/k$ at zero power (Ref. 5). This evaluation may require a computer calculation of the maximum ejected rod worth based on nonstandard configurations of the CONTROL ROD groups. The evaluation must determine the ejected rod worth for the remainder of the fuel cycle to ensure a valid evaluation, should fuel cycle conditions at some later time become more bounding than those at the time of the rod misalignment. The required Completion Time of 72 hours is acceptable because LHRs are limited by the THERMAL POWER reduction and sufficient time is provided to perform the required evaluation.

A.6

Performance of SR 3.2.5.1 provides a determination of the power peaking factors using the Incore Detector System. Verification of the F_Q and $F^N_{\Delta H}$ from an incore power distribution map is necessary to ensure that excessive local LHRs will not occur due to CONTROL ROD misalignment. This is necessary because the assumption that all CONTROL RODS are aligned (used to determine the regulating rod insertion, AXIAL POWER IMBALANCE, and QPT limits) is not valid when

BASES

ACTIONS

A.6 (continued)

the CONTROL RODS are not aligned. The required Completion Time of 72 hours is acceptable because LHRs are limited by the THERMAL POWER reduction and adequate time is allowed to obtain an incore power distribution map.

Required Action A.6 is modified by a Note that requires the performance of SR 3.2.5.1 only when THERMAL POWER is greater than 20% RTP. This establishes a Required Action that is consistent with the Applicability of LCO 3.2.5, "Power Peaking Factors."

B.1

If any Required Action and associated Completion Time of Condition A cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

C.1.1

More than one CONTROL ROD becoming misaligned, is not expected and may violate the minimum SDM requirement. Therefore, SDM must be evaluated. Ensuring the SDM meets the minimum requirement within 1 hour allows the operator adequate time to determine the SDM.

C.1.2

Restoration of the required SDM requires increasing the RCS boron concentration to provide negative reactivity. RCS boration must occur as described in the LCO 3.1.1 Bases. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time for aligning the required valves and starting the boric acid pumps. Boration will continue until the required SDM is restored.

BASES

ACTIONS (continued)

C.2

If more than one CONTROL ROD is misaligned, continued operation of the reactor may cause the misalignment to increase, as the regulating rods insert or withdraw to control reactivity. If the CONTROL ROD misalignment increases, local power peaking may also increase, and local LHRs will also increase if the reactor continues operation at THERMAL POWER. The SDM is decreased when one or more CONTROL RODS become misaligned by insertion from the group average position.

Therefore, it is prudent to place the reactor in MODE 3. LCO 3.1.4 does not apply in MODE 3 since excessive power peaking cannot occur and the minimum required SDM is ensured. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

D.1.1 and D.1.2

When one or more CONTROL RODs are inoperable, the SDM may be adversely affected. Under these conditions, it is important to determine the SDM and, if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration to restore SDM.

In this situation, SDM verification must include the worth of the inoperable rod(s) as well as a rod of maximum worth.

D.2

If the inoperable CONTROL RODs cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rods are aligned within 6.5% of their group average height limits at a 12 hour Frequency allows the operator to detect a rod that is beginning to deviate from its expected position. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

SR 3.1.4.2

Verifying each CONTROL ROD is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each CONTROL ROD could result in radial tilts. Exercising each individual CONTROL ROD that is not fully inserted every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each CONTROL ROD by 3% will not cause radial or axial power tilts, or oscillations, to occur. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.4.2 (determination of CONTROL ROD OPERABILITY by movement), if a CONTROL ROD(S) is discovered to be immovable, but is determined to be trippable, the CONTROL ROD(S) is considered to be OPERABLE. At any time, if a CONTROL ROD(S) is immovable, a determination of the trippability (OPERABILITY) of the CONTROL ROD(S) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop time allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. The rod drop time given in the safety analysis is 1.4 seconds to 2/3 insertion. Using the identical rod drop curve gives a value of 1.58 seconds to 3/4 insertion. The latter value is used in the Surveillance because the zone reference lights are located at 3/4 insertion, which provides the most accurate position indication. The zone reference lights will activate at 3/4 insertion to give an indication of the rod drop time and rod location. Measuring rod drop times, prior to reactor criticality after reactor vessel head removal, ensures that the reactor internals and CRDM will not interfere with CONTROL ROD motion or rod drop time. This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.3 (continued)

This testing is normally performed with all reactor coolant pumps operating and average moderator temperature ≥ 525°F to simulate a reactor trip under actual conditions. However, if the rod drop times are determined with less than four reactor coolant pumps operating, a Note allows power operation to continue, provided operation is restricted to the pump combination utilized during the rod drop time determination.

REFERENCES

1. UFSAR, Appendices 3D.1.6, Criterion 10 – Reactor Design; 3D.1.21, Criterion 25 – Protection System Requirements For Reactivity Control Malfunctions; 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability; 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability; and 3D.1.24, Criterion 28 – Reactivity Limits.

2. 10 CFR 50.46.

3. UFSAR, Section 15.2.3.

4. UFSAR, Section 15.1.2.

5. UFSAR, Section 15.4.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Safety Rod Insertion Limits

BASES

BACKGROUND

The insertion limits of the safety rods are initial condition assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power distributions and assumptions of available SDM, ejected rod worth, and initial reactivity insertion rate.

The applicable criteria for the reactivity and power distribution design requirements are UFSAR, Appendices 3D.1.6, 3D.1.21, 3D.1.22, 3D.1.23, and 3D.1.24 (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

Limits on safety rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the reactivity limits, ejected rod worth, and SDM limits are preserved.

The regulating groups are used for precise reactivity control of the reactor. The positions of the regulating groups are normally automatically controlled by the control system, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The regulating groups must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal operations. Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature and fuel burnup.

The safety groups can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The safety groups are controlled manually by the control room operator. During normal full power operation, the safety groups are fully withdrawn. The safety groups must be completely withdrawn from the core prior to withdrawing any regulating groups during an approach to criticality. The safety groups remain in the fully withdrawn position until the reactor is shut down or if being tested in accordance with SR 3.1.4.2. They add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

BASES

APPLICABLE SAFETY ANALYSES

On a reactor trip, all rods (safety groups and regulating groups), except the most reactive rod, are assumed to insert into the core. The safety groups shall be at their fully withdrawn limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The regulating groups may be partially inserted in the core as allowed by LCO 3.2.1, "Regulating Rod Insertion Limits." The safety group and regulating rod insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of regulating groups and safety groups (less the most reactive rod, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power and to maintain the required SDM at rated no load temperature (Ref. 3). The safety group insertion limit also limits the reactivity worth of an ejected safety rod.

The safety rod insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The safety groups must be fully withdrawn any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

This LCO has been modified by a Note indicating the LCO requirement is suspended for those safety rods which are inserted solely due to testing in accordance with SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the safety group to move below the LCO limits, which would normally violate the LCO.

APPLICABILITY

The safety groups must be within their insertion limits with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

ACTIONS

A.1.1, A.1.2, and A.2

The safety rod must be declared misaligned within a 1 hour time frame. This requires entry into Condition A of LCO 3.1.4, "CONTROL ROD Group Alignment Limits." In addition, since the safety rod may be inserted farther than the group average insertion for a long time, SDM must be evaluated. Ensuring the SDM meets the minimum requirement within 1 hour is adequate to determine that further degradation of the SDM is not occurring.

BASES

ACTIONS

A.1.1, A.1.2, and A.2 (continued)

Restoration of the required SDM requires increasing the boron concentration, since the safety rod may remain misaligned and not be providing its normal negative reactivity on tripping. RCS boration must occur as described in the LCO 3.1.1 Bases. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time for aligning the required valves and starting the boric acid pumps. Boration will continue until the required SDM is restored.

The allowed Completion Time of 1 hour provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1.1 and B.1.2

When more than one safety rod is not fully withdrawn, there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration to restore SDM.

In this situation, SDM verification must include the worth of the untrippable rod as well as the rod of maximum worth.

B.2

If more than one safety rod is not fully withdrawn the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that each safety rod is fully withdrawn ensures the rods are available to provide reactor shutdown capability.

Verification that individual safety rod positions are fully withdrawn at a 12 hour Frequency allows the operator to detect a rod beginning to deviate from its expected position. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of the safety rods.

REFERENCES

1. UFSAR, Appendices 3D.1.6, Criterion 10 – Reactor Design; 3D.1.21, Criterion 25 – Protection System Requirements For Reactivity Control Malfunctions; 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability; 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability; and 3D.1.24, Criterion 28 – Reactivity Limits.

2. 10 CFR 50.46.

3. UFSAR, Section 15.4.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 AXIAL POWER SHAPING ROD (APSR) Alignment Limits

BASES

BACKGROUND

The OPERABILITY of the APSRs and rod misalignment are initial condition assumptions in the safety analysis that directly affect core power distributions. The applicable criteria for these power distribution design requirements are UFSAR, Appendices 3D.1.6, 3D.1.21, 3D.1.22, 3D.1.23, and 3D.1.24 (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

Mechanical or electrical failures may cause an APSR to become inoperable or to become misaligned from its group. APSR inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution. Therefore, APSR alignment and OPERABILITY are related to core operation within design power peaking limits.

Limits on APSR alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution limits defined by the design peaking limits are preserved.

CONTROL RODS and APSRs are moved by their CONTROL ROD drive mechanisms (CRDMs). Each CRDM moves its rod 3/4 inch for one revolution of the roller nut assembly around the leadscrew at varying rates depending on the signal output from the Rod Control System.

The APSRs are arranged into rod groups that are radially symmetric. Therefore, movement of the APSRs does not introduce radial asymmetries in the roller nut assembly around the core power distribution. The APSRs, which control the axial power distribution, are positioned manually and do not trip.

APPLICABLE SAFETY ANALYSES

There are no explicit safety analyses associated with misalignment of APSRs. The LCOs governing APSR alignment are provided because the power distribution analysis supporting 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)," assumes the APSRs are OPERABLE and aligned within limits.

Misaligned APSRs may cause excessive power peaking. Continued operation of the reactor with a misaligned APSR is allowed if the power distribution limits of Section 3.2, "Power Distribution Limits," are preserved.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The APSR alignment limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on CONTROL ROD group alignment, safety rod insertion, and APSR alignment, together with the limits on regulating rod insertion, APSR insertion, AXIAL POWER IMBALANCE, and QPT, ensure the reactor will operate within the fuel design criteria. The Required Action in this LCO ensures deviations from the alignment limits will be adjusted so that excessive local LHRs will not occur.

The limit for individual APSR misalignment is 6.5% (9 inches) deviation from the group average position. This value is established based on the distance between reed switches, with additional allowances for uncertainty in the absolute position indicator amplifiers and asymmetric alarm or fault circuits. The position of a misaligned rod is not included in the calculation of the rod group's average position.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors, and LHRs, which may constitute initial conditions inconsistent with the safety analysis.

APPLICABILITY

The requirements on APSR OPERABILITY, unless fully withdrawn, and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. The APSRs are not required to be OPERABLE when fully withdrawn because, once they are fully withdrawn, they are prohibited by the APSR insertion limits from being inserted and the normal power supply is normally disabled to prevent their movement. While APSRs are not required OPERABLE when fully withdrawn, they are still required to meet the alignment limits. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the reactor is shut down and not producing fission power, and excessive local LHRs cannot occur from APSR misalignment.

ACTIONS

A.1

The ACTIONS described below are required if one APSR is inoperable, not aligned within its limit, or both. The plant is not allowed to operate with more than one inoperable APSR. This would require the reactor to be shut down, in accordance with LCO 3.0.3.

An alternate to realigning a single misaligned APSR to the group average position is to align the remainder of the APSR group to the position of the misaligned or inoperable APSR, while maintaining APSR insertion, in

BASES

ACTIONS

A.1 (continued)

accordance with the limits in the COLR. This restores the alignment requirements. Deviations up to 2 hours will not cause significant xenon redistribution to occur. This alternative assumes the APSR group movement does not cause the limits of LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," to be exceeded. For this reason, APSR group movement is only practical for instances where small movements of the APSR group are sufficient to re-establish APSR alignment.

The reactor may continue in operation with the APSR misaligned if the limits on AXIAL POWER IMBALANCE are surveilled within 2 hours to determine if the AXIAL POWER IMBALANCE is still within limits. Also, since any additional movement of the APSRs may result in additional imbalance, Required Action A.1 also requires the AXIAL POWER IMBALANCE Surveillance to be performed again within 2 hours after each APSR movement. The required Completion Time of up to 2 hours will not cause significant xenon redistribution to occur.

B.1

The plant must be brought to a MODE in which the LCO does not apply if the Required Actions and associated Completion Times cannot be met. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from RTP in an orderly manner and without challenging plant systems. In MODE 3, APSR group alignment limits are not required because the reactor is not generating THERMAL POWER and excessive local LHRs cannot occur from APSR misalignment.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

Verification at a 12 hour Frequency that individual APSR positions are within 6.5% of the group average height limits allows the operator to detect an APSR beginning to deviate from its expected position. In addition, APSR position is continuously available to the operator in the control room so that during actual rod motion, deviations can immediately be detected.

BASES

REFERENCES

1. UFSAR, Appendices 3D.1.6, Criterion 10 – Reactor Design; 3D.1.21, Criterion 25 – Protection System Requirements For Reactivity Control Malfunctions; 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability; 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability; and 3D.1.24, Criterion 28 – Reactivity Limits.

2. 10 CFR 50.46.

3. UFSAR, Section 15.2.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Position Indicator Channels

BASES

BACKGROUND

According to UFSAR, Appendix 3D.1.9 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the CONTROL ROD and APSR position indicators, and thereby ensure compliance with the CONTROL ROD and APSR alignment and insertion limits.

The OPERABILITY, including position indication, of the safety and regulating rods is an initial condition assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment for the safety rods, regulating rods, and APSRs is assumed in the safety analysis, which directly affects core power distributions and assumptions of available SDM.

Mechanical or electrical failures may cause a CONTROL ROD or APSR to become misaligned from its group. CONTROL ROD or APSR misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, CONTROL ROD and APSR alignment are related to core operation within design power peaking limits and the core design requirement of a minimum SDM. Rod position indication is needed to assess rod OPERABILITY and alignment.

Limits on CONTROL ROD alignment, APSR alignment, and safety rod position have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Two methods of CONTROL ROD and APSR position indication are provided in the Control Rod Drive Control System. The two means are by absolute position indicator and relative position indicator. The absolute position indicator is essentially fully redundant consisting of two independent voltage dividers, each with a series of magnetically operated reed switches mounted in a tube parallel to the control rod drive mechanism (CRDM) motor tube extension. Switch contacts close when a permanent magnet mounted on the upper end of the control rod assembly (CRA) leadscrew extension comes near. As the leadscrew and CRA move, the switches operate sequentially, producing an analog voltage

BASES

BACKGROUND (continued)

proportional to position. This analog voltage consists of two output channels that are averaged by the CRDCS controller to form a single composite analog position indicator signal. If during the DCRDCS API median select checking process a channel of API is determined to be bad or inactive, the CRDCS controller will automatically select only the good channel which will be used for API calculations and display. If both channels are considered bad, the average of the two channels will be used for all API calculations and display. The control room operator is notified if an API string is removed from the API average through the plant computer. Other reed switches included in the same tube with the position indicator matrix provide full in and full out limit indications, and absolute position indications at 0%, 25%, 50%, 75%, and 100% travel (called zone reference indicators). The relative position indicator is a potentiometer, driven by a step motor that produces a signal proportional to CONTROL ROD position, based on the electrical pulse steps that drive the CRDM.

Control rod position-indicating readout devices in the control room consist of two control panel-mounted position indication display video monitors. Relative, absolute position and group average position information is displayed on the rod position displays. The group average values displayed on the position indication monitors display the arithmetic average of the absolute position signals of all CRAs in a group. Each of the two video monitors normally displays four groups, 1 – 4 and 5 – 8. Either monitor can display either set of rod groups. The PI monitor panel displays each rod API value via a bar graph and numeric percentage and the RPI value via a numeric percentage. The PI monitor panel indicates if a rod is ON Control and indicates if the rod has an asymmetric alarm or fault compared to the API group average. The display also indicates percentage withdrawn for each group from the calculated API group average. Below the PI monitors are LEDs for each rod 0% withdrawn zone reference indication. These LEDs have a battery back-up through the station battery to ensure the 0% indication is available upon a loss of all power to the CRD system. The consequence of continued operation with an inoperable absolute position indicator or relative position indicator channel is a decreased reliability in determining control rod position. Therefore, the potential for operation in violation of design peaking factors or SDM is increased.

APPLICABLE SAFETY ANALYSES

CONTROL ROD and APSR position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2) with CONTROL RODS or APSRs operating outside their limits undetected. Regulating rod, safety rod, and APSR positions must be known in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Safety Rod

BASES

APPLICABLE SAFETY ANALYSES (continued)

Insertion Limits," LCO 3.2.1, "Regulating Rod Insertion Limits," and LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "CONTROL ROD Group Alignment Limits," and LCO 3.1.6, "AXIAL POWER SHAPING ROD (APSR) Alignment Limits"). CONTROL ROD and APSR positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions. The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an accident initial condition.

LCO

LCO 3.1.7 specifies that one absolute position indicator channel and one relative position indicator channel be OPERABLE for each CONTROL ROD and APSR.

The agreement between the relative position indicator channel and the absolute position indicator channel, within the limit given in the COLR, indicates that relative position indicators are adequately calibrated and can be used for indication of the measurement of CONTROL ROD group position. A deviation of less than the allowable limit, given in the COLR, in position indication for a single CONTROL ROD or APSR, ensures confidence that the position uncertainty of the corresponding CONTROL ROD group or APSR group is within the assumed values used in the analysis that specifies CONTROL ROD group and APSR insertion limits.

These requirements ensure that CONTROL ROD and APSR position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned CONTROL RODS or APSRs can be detected. Therefore, power peaking and SDM can be controlled within acceptable limits.

APPLICABILITY

In MODES 1 and 2, OPERABILITY of position indicator channels is required, since the reactor is, or is capable of, generating THERMAL POWER in these MODES. In MODES 3, 4, 5, and 6, Applicability is not required because the reactor is shut down with the required minimum SDM and is not generating THERMAL POWER.

ACTIONS

A.1

If the relative position indicator channel is inoperable for one or more rods, the position of the rod(s) is still monitored by the absolute position indicator channel for each affected rod. The absolute position indicator channel may be used if it is determined to be OPERABLE. The required Completion Time of 8 hours is reasonable to provide adequate time for

BASES

ACTIONS (continued)

A.1 (continued)

the operator to determine position indicator channel status. Continuing the verification every 8 hours thereafter in the applicable condition is acceptable, based on the fact that during normal power operation excessive movement of the groups is not required. Also, if the rod is out of position during this 8 hour period, the simultaneous occurrence of an event sensitive to the rod position has a small probability.

B.1.1 and B.1.2

If the absolute position indicator channel is inoperable for one or more rods, the position of the rod(s) is monitored by the relative position indicator channel for each affected rod. However, the relative position indicator channel is not as reliable a method of monitoring rod position as the absolute position indicator because it counts electrical pulse steps driving the CRDM motor rather than actuating a switch located at a known elevation. Therefore, the affected rod's position can be determined with more certainty by actuating one of its zone reference indicator switches located at discrete elevations (Required Action B.1.1). The required Completion Time of 8 hours provides the operator adequate time for adjusting the affected rod's position to an appropriate zone reference indicator location. If the rod is out of position during this 8 hour period, the simultaneous occurrence of an event sensitive to the rod position has a small probability.

To allow continued operation, Required Action B.1.2 requires the rods with inoperable absolute position indicator channels to be maintained at the zone reference indicator position. In addition, the affected rods must be maintained within the limits of LCO 3.1.5 (when the affected rod is a safety rod), LCO 3.2.1 (when the affected rod is a regulating rod), or LCO 3.2.2 (when the affected rod is an APSR). This Required Action ensures safety rods remain fully withdrawn, and that regulating rods and APSRs remain aligned within their insertion limits. The required Completion Time of 8 hours is reasonable for allowing the operator adequate time to determine the affected rods are in compliance with these LCOs. Continuing to verify the rod positions every 8 hours thereafter is reasonable for ensuring that rod alignment and insertion are not changing, and provides the operator adequate time to correct any deviation that may occur. Continuing the verification every 8 hours thereafter in the applicable condition is acceptable, based on the fact that during normal power operation excessive movement of the groups is not required. Also, if the rod is out of position during this 8 hour period, the simultaneous occurrence of an event sensitive to the rod position has a small probability.

BASES

ACTIONS (continued)

B.2.1 and B.2.2

Note: Davis-Besse does not currently have the computer software installed to allow use of the fixed incore instrumentation, as described below. Therefore, before this option is used, the proper software must be installed.

If the absolute position indicator is inoperable for one or more rods, the position of the rod is monitored by the relative position indicator channel for each affected rod. However, the relative position indicator channel is not as reliable a method of monitoring rod position as the absolute position indicator because it counts electrical pulse steps. Therefore, Required Actions B.2.1 and B.2.2 provide the option to indirectly determine the position of the rod. The fixed incore system can be used to indirectly determine the absolute position of the affected rod. The fixed incore instrumentation can provide a continual update of control rod position; therefore this method can be used to allow continued operation of the reactor with a manual CONTROL ROD movement, while maintaining verification of control rod insertion and alignment. Required Action B.2.1 restricts rod motion by placing the groups with nonindicating rods in manual control; thus, even if the rod fails to move in alignment with the group, misalignment is limited. The required Completion Time of 8 hours provides the operator adequate time for placing the rods in manual control, and is consistent with the required Completion Time for Required Action B.1.1. If the rod is out of position during this 8 hour period, the simultaneous occurrence of an event sensitive to the rod position has a small probability.

Continuing to verify the rod positions (Required Action B.2.2) every 8 hours is reasonable for ensuring that rod alignment and insertion are not changing, and provides the operator adequate time to correct any deviation that may occur. The additional Completion Time of 1 hour after motion of nonindicating rods, which exceeds 11% in one direction since the last determination of the rod's position, ensures that the rod with inoperable position indication will not be misaligned for a significant period of time, in the event the rod is moved. The specified Completion Times are acceptable because the simultaneous occurrence of a mispositioned rod and an event sensitive to the rod position has a small probability.

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time is not met or if both the absolute position indicator channel and relative position indicator channel are inoperable for one or more rods, the position of the rod(s) is not known with certainty. Therefore, each affected rod must be declared inoperable, and the limits of LCO 3.1.4 or LCO 3.1.6 apply. The required Completion Time for declaring the rod(s) inoperable is immediately. Therefore LCO 3.1.4 or LCO 3.1.6 is entered immediately, and the required Completion Times for the appropriate Required Actions in those LCOs apply without delay.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification is required that the Absolute Position Indicator channels and Relative Position Indicator channels agree within the limit given in the COLR. This verification ensures that the Relative Position Indicator channels, which are regarded as the potentially less reliable means of position indication, remain OPERABLE and accurate. The required Frequency of 12 hours is adequate for verifying that no degradation in system OPERABILITY has occurred.

REFERENCES

1. UFSAR, Appendix 3D.1.9, Criterion 13 – Instrumentation and Control.

2. UFSAR, Section 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions Systems - MODE 1

BASES

BACKGROUND

The purpose of this MODE 1 LCO is to permit PHYSICS TESTS to be conducted by providing exemptions from the requirements of other LCOs. Establishment of a test program to verify that structures, systems, and components will perform satisfactorily in service is required by Section XI of 10 CFR 50, Appendix B (Ref. 1). Testing is required as an integral part of the design, fabrication, construction, and operation of the power plant. All functions necessary to ensure that specified design conditions are not violated during normal operation and anticipated operational occurrences must be tested. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality; during startup, low power operations, and power ascension; at high powers; and after each fueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions, and that the core can be operated as designed (Ref. 4).

PHYSICS TESTS procedures are written and approved in accordance with established guidelines. The procedures include all information necessary to permit a detailed execution of testing required to ensure the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are approved prior to continued power escalation and long term power operation. Examples of PHYSICS TESTS include determination of critical boron concentration, CONTROL ROD group worths, reactivity coefficients, flux symmetry, and core power distribution.

BASES

APPLICABLE SAFETY ANALYSES

It is acceptable to suspend certain LCOs for PHYSICS TESTS because reactor protection criteria are preserved by the LCOs still in effect and by the SRs. Even if an accident occurs during PHYSICS TESTS with one or more LCOs suspended, fuel damage criteria are preserved because the limits on nuclear hot channel factors, ejected rod worth, and shutdown capability are maintained during the PHYSICS TESTS.

Reference 5 defines requirements for initial testing of the facility, including PHYSICS TESTS. UFSAR, Tables 14.1-2 and 14.1-3 (Ref. 6) summarize the post-initial fuel loading - precritical testing and post-criticality test, respectively. Requirements for reload fuel cycle PHYSICS TESTS are given in UFSAR, Appendix 4B (Ref. 4). A summary of the PHYSICS TESTS for each cycle are listed in Reference 7. Although these PHYSICS TESTS are generally accomplished within the limits of all LCOs, one or more LCOs must sometimes be suspended to make completion of PHYSICS TESTS possible or practical.

This is acceptable as long as the fuel design criteria are not violated. When one or more of the limits specified in:

LCO 3.1.4, "CONTROL ROD Group Alignment Limits;"
LCO 3.1.5, "Safety Rod Insertion Limits;"
LCO 3.1.6, "AXIAL POWER SHAPING ROD (APSR) Alignment Limits;"
LCO 3.2.1, "Regulating Rod Insertion Limits," for the restricted operation region only;
LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits;"
LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits;" or
LCO 3.2.4, "QUADRANT POWER TILT (QPT)"

are suspended for PHYSICS TESTS, the fuel design criteria are preserved by maintaining the nuclear hot channel factors (in MODE 1 PHYSICS TESTS) within their limits, maintaining ejected rod worth within limits by restricting regulating rod insertion to within the acceptable operating region or the restricted operating region, by limiting maximum THERMAL POWER and by maintaining SDM within the limits specified in the COLR. Therefore, surveillance of the F_Q, the $F^N_{\Delta H}$, and SDM is required to verify that their limits are not exceeded. The limits for the nuclear hot channel factors are specified in the COLR. Refer to the Bases for LCO 3.2.5 for a complete discussion of F_Q and $F^N_{\Delta H}$. During PHYSICS TESTS, one or more of the LCOs that normally preserve the F_Q and $F^N_{\Delta H}$ limits may be suspended. However, the results of the safety analysis are not adversely impacted if verification that F_Q and $F^N_{\Delta H}$ are within their limits is obtained, while one or more of the LCOs is

BASES

APPLICABLE SAFETY ANALYSES (continued)

suspended. Therefore, SRs are placed on F_Q and $F^N_{\Delta H}$ during MODE 1 PHYSICS TESTS when THERMAL POWER exceeds 20% RTP to verify that these factors remain within their limits. Periodic verification of these factors allows PHYSICS TESTS to be conducted while continuing to maintain the design criteria.

PHYSICS TESTS include measurement of core nuclear parameters or exercise of control components that affect process variables. Among the process variables involved are AXIAL POWER IMBALANCE and QPT, which represent initial condition input (power peaking) for the accident analysis. Also involved are the movable control components, i.e., the regulating rods and the APSRs, which affect power peaking. The regulating rods are also required for shutdown of the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

As described in LCO 3.0.7, compliance with Test Exceptions LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exceptions LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

This LCO permits individual control rods to be positioned outside of their specified group alignment and withdrawal limits and to be assigned to other than specified control rod groups, and permits AXIAL POWER IMBALANCE and QPT limits to be exceeded during the performance of PHYSICS TESTS. In addition, this LCO permits verification of the fundamental core characteristics and nuclear instrumentation operation.

The requirements of LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, LCO 3.2.1 (for the restricted operation region only), LCO 3.2.2, LCO 3.2.3, and LCO 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. THERMAL POWER is maintained ≤ 85% RTP;

b. High Flux trip setpoint is ≤ 10% RTP higher than the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP;

c. F_Q and $F^N_{\Delta H}$ are maintained within limits specified in the COLR while operating at greater than 20% RTP; and

d. SDM is maintained within the limits specified in the COLR.

BASES

LCO (continued)

Operation with THERMAL POWER ≤ 85% RTP during PHYSICS TESTS provides an acceptable thermal margin when one or more of the applicable LCOs is out of specification. Eighty-five percent RTP is consistent with the maximum power level for conducting the intermediate core power distribution test specified in Reference 4. The High Flux trip setpoint is reduced so that a similar margin exists between the steady state condition and trip setpoint as exists during normal operation at RTP.

LCO provision c is modified by a Note that requires the adherence to power peaking factor requirements only when THERMAL POWER is greater than 20% RTP. This establishes an LCO provision that is consistent with the Applicability of LCO 3.2.5, "Power Peaking Factors."

APPLICABILITY

This LCO is applicable in MODE 1, when the reactor has completed low power testing and is in power ascension, or during power operation with THERMAL POWER > 5% RTP but ≤ 85% RTP. This LCO is applicable for power ascension testing, as defined by Regulatory Guide 1.68 (Ref. 3). In MODE 2, Applicability of this LCO is not required because LCO 3.1.9, "PHYSICS TESTS Exceptions - MODE 2," addresses PHYSICS TESTS exceptions in MODE 2. In MODES 3, 4, 5, and 6, Applicability is not required because PHYSICS TESTS are not performed in these MODES.

ACTIONS

A.1 and A.2

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. Boration will be continued until SDM is within limit. In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid addition tanks or the borated water storage tank. The operator should begin boration with the best source available for the plant conditions.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

BASES

ACTIONS (continued)

B.1

If THERMAL POWER exceeds 85% RTP, then 1 hour is allowed for the operator to reduce THERMAL POWER to within limits or to complete an orderly suspension of PHYSICS TESTS exceptions. Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable individual LCOs to within specification. This required Completion Time is consistent with, or more conservative than, those specified for the individual LCO, addressed by PHYSICS TESTS exceptions.

If the High Flux trip setpoint is not within the specified limits, then 1 hour is allowed for the operator to restore the High Flux trip setpoint within limits or to complete an orderly suspension of PHYSICS TESTS exceptions. Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable individual LCOs to within specification. This required Completion Time is consistent with, or more conservative than, those specified for the individual LCO, addressed by these PHYSICS TESTS exceptions.

If the results of the incore flux map indicate that either F_Q or $F^N_{\Delta H}$ has exceeded its limit when THERMAL POWER is greater than 20% RTP, then PHYSICS TESTS are suspended. This action is required because of direct indication that the core peaking factors, which are fundamental initial conditions for the safety analysis, are excessive. Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

This Condition is modified by a Note that requires performance of the Required Action only when THERMAL POWER is greater than 20% RTP. This establishes an ACTIONS entry Condition that is consistent with LCO provision c and the Applicability of LCO 3.2.5, "Power Peaking Factors."

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

Verification that THERMAL POWER is ≤ 85% RTP ensures that the required additional thermal margin has been established prior to and during PHYSICS TESTS. The required Frequency of once per hour allows the operator adequate time to determine any degradation of the established thermal margin during PHYSICS TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.2

Verification that F_Q and $F^N_{\Delta H}$ are within their limits ensures that core local linear heat rate and departure from nucleate boiling ratio will remain within their limits, while one or more of the LCOs that normally control these design limits are out of specification. The required Frequency of 2 hours allows the operator adequate time for collecting a flux map and for performing the hot channel factor verifications, based on operating experience. If SR 3.2.5.1 is not met, PHYSICS TESTS are suspended and LCO 3.2.5 applies. This Frequency is more conservative than the Completion Time for restoration of the individual LCOs that preserve the F_Q and $F^N_{\Delta H}$ limits.

This SR is modified by a Note that requires performance only when THERMAL POWER is greater than 20% RTP. This establishes a performance requirement that is consistent with the Applicability of LCO 3.2.5, "Power Peaking Factors."

SR 3.1.8.3

Verification that the High Flux trip setpoint is within the limit specified for each PHYSICS TEST ensures that core protection at the reduced power level is established and will remain in place during the PHYSICS TESTS. Performing the verification once every 8 hours allows the operator adequate time for determining any degradation of the established trip setpoint margin before and during PHYSICS TESTS and for adjusting the High Flux trip setpoint.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering, but not limited to, the following reactivity effects:

a. Reactor Coolant System (RCS) boron concentration;

b. Control rod position;

c. Doppler defect;

d. Fuel burnup based on gross thermal energy generation;

e. Samarium concentration;

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.4 (continued)

f. Xenon concentration; and

g. Moderator defect.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 2, August 1978.

4. UFSAR, Appendix 4B.

5. UFSAR, Section 14.1.

6. UFSAR, Tables 14.1-2 and 14.1-3.

7. UFSAR, Appendix 4B, Section 9.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.9 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The purpose of this MODE 2 LCO is to permit PHYSICS TESTS to be conducted by providing exemptions from the requirements of other LCOs. Establishment of a test program to verify that structures, systems, and components will perform satisfactorily in service is required by 10 CFR 50, Appendix B (Ref. 1). Testing is required as an integral part of the design, fabrication, construction, and operation of the power plant. All functions necessary to ensure that specified design conditions are not violated during normal operation and anticipated operational occurrences must be tested. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality; during startup, low power operations, and power ascension; at high powers; and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions, and that the core can be operated as designed (Ref. 4).

PHYSICS TESTS procedures are written and approved in accordance with established guidelines. The procedures include all information necessary to permit a detailed execution of testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are approved prior to continued power escalation and long term power operation.

Examples of MODE 2 PHYSICS TESTS include determination of critical boron concentration, control rod group worth, and reactivity coefficients.

BASES

APPLICABLE SAFETY ANALYSES

Reference 5 defines requirements for initial testing of the facility, including PHYSICS TESTS. UFSAR, Tables 14.1-2 and 14.1-3 (Ref. 6) summarize the post-initial fuel loading - precritical testing and post-criticality test, respectively. Requirements for reload fuel cycle PHYSICS TESTS are given in UFSAR, Appendix 4B (Ref. 4). A summary of the PHYSICS TESTS for each cycle are listed in Reference 7. Although these PHYSICS TESTS are generally accomplished within the limits of all LCOs, conditions may occur when one or more of the LCOs must be suspended to make completion of PHYSICS TESTS possible or practical.

It is acceptable to suspend the following LCOs for PHYSICS TESTS because reactor protection criteria are preserved by the LCOs still maintained and by the SRs:

LCO 3.1.3, "Moderator Temperature Coefficient (MTC);"
LCO 3.1.4, "CONTROL ROD Group Alignment Limits;"
LCO 3.1.5, "Safety Rod Insertion Limits;"
LCO 3.1.6, "AXIAL POWER SHAPING ROD (APSR) Alignment Limits;"
LCO 3.2.1, "Regulating Rod Insertion Limits," for the sequence and overlap limits, and the insertion limits for the restricted operation region only;
LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits;" and
LCO 3.4.2, "RCS Minimum Temperature for Criticality."

Even if an accident occurs during PHYSICS TESTS with one or more LCOs suspended, fuel damage criteria are preserved because the limits on THERMAL POWER and shutdown capability are maintained during the PHYSICS TESTS.

Shutdown capability is preserved by limiting maximum obtainable THERMAL POWER and maintaining adequate SDM, when in MODE 2 PHYSICS TESTS. In MODE 2, the Reactor Coolant System (RCS) temperature must be within the narrow range instrumentation for plant control. The narrow range temperature instrumentation goes on scale at 520°F. Therefore, it is considered safe to allow the minimum RCS temperature to decrease to 520°F during MODE 2 PHYSICS TESTS, based on the low probability of an accident occurring and on prior operating experience.

PHYSICS TESTS include measurement of core nuclear parameters or exercise of control components that affect process variables.

As described in LCO 3.0.7, compliance with Test Exceptions LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. Test Exceptions LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

BASES

LCO

This LCO permits individual control rods to be positioned outside of their specified group alignment and withdrawal limits and to be assigned to other than specified control rod groups during the performance of PHYSICS TESTS. In addition, this LCO permits verification of the fundamental core characteristics.

This LCO also allows suspension of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, LCO 3.2.1 (except for the insertion limits for the unacceptable operation region), LCO 3.2.2, and LCO 3.4.2, provided:

a. THERMAL POWER is ≤ 5% RTP;

b. High Flux trip setpoints on the OPERABLE nuclear power range channels are set to ≤ 25% RTP;

c. Nuclear instrumentation high startup rate control rod withdrawal inhibit is OPERABLE;

d. SDM is maintained within the limits specified in the COLR; and

e. RCS lowest loop average temperature is ≥ 520°F.

The limits of LCO 3.2.3 and LCO 3.2.4 do not apply in MODE 2. Inhibiting control rod withdrawal, based on startup rate, also limits local linear heat rate (LHR), departure from nucleate boiling ratio (DNBR), and peak RCS pressure during accidents initiated from low power.

APPLICABILITY

This LCO is applicable when the reactor is either subcritical or critical with THERMAL POWER ≤ 5% RTP. The Applicability is stated as "during PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RTP maximum power level is not exceeded. Should the THERMAL POWER exceed 5% RTP, and consequently the unit enter MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions. This LCO is applicable for initial criticality or low power testing, as defined by Regulatory Guide 1.68 (Ref. 3). In MODE 1, Applicability of this LCO is not required because LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 1," addresses PHYSICS TESTS exceptions in MODE 1. In MODES 3, 4, 5, and 6, Applicability is not required because physics testing is not performed in these MODES.

ACTIONS

A.1

If THERMAL POWER exceeds 5% RTP, a positive reactivity addition could be occurring, and a nuclear excursion could result. To ensure that local LHR, DNBR, and RCS pressure limits are not violated, the reactor is tripped. The necessary prompt action requires manual operator action to

BASES

ACTIONS

A.1 (continued)

open the CONTROL ROD drive trip breakers without attempts to reduce THERMAL POWER by actuating the control system (i.e., CONTROL ROD insertion or RCS boration).

B.1 and B.2

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. Boration will be continued until SDM is within limit. In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid addition tanks or the borated water storage tank. The operator should begin boration with the best source available for the plant conditions.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

C.1

If the RCS lowest loop average temperature is < 520°F, then 30 minutes is allowed for the operator to restore the RCS lowest loop average temperature to within limits or to complete an orderly suspension of PHYSICS TESTS exceptions. The required Completion Time is consistent with, or more conservative than, those specified in the individual LCOs addressed by the PHYSICS TESTS exceptions.

D.1

If the High Flux trip setpoint is > 25% RTP, then 1 hour is allowed for the operator to restore the High Flux trip setpoint within limits or to complete an orderly suspension of PHYSICS TESTS exceptions. Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable individual LCOs to within specification, in order to ensure that continuity of reactor operation is within initial condition limits. This required Completion Time is consistent with, or more conservative than, those specified for the individual LCOs addressed by PHYSICS TESTS exceptions.

BASES

ACTIONS

D.1 (continued)

If the nuclear instrumentation high startup rate control rod withdrawal inhibit function is inoperable, then 1 hour is allowed for the operator to restore the function to OPERABLE status or to complete an orderly suspension of PHYSICS TESTS exceptions. Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable individual LCOs to within specification. This required Completion Time is consistent with, or more conservative than, those specified for the individual LCOs addressed by PHYSICS TESTS exceptions.

The nuclear instrumentation high startup rate control rod withdrawal inhibit function is not required when the reactor power level is above the operating range of the instrumentation channel. For example, if the reactor power level is above the source range channel operating range, then only the intermediate range high startup rate control rod withdrawal inhibit is required to be functional.

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1

Performing a CHANNEL FUNCTIONAL TEST on each nuclear instrumentation source and intermediate range high startup rate control rod withdrawal inhibit and High Flux channel, ensures that the instrumentation required to detect a deviation from THERMAL POWER or to detect a high startup rate is OPERABLE. Performing the test once within 24 hours, prior to initiating PHYSICS TESTS, ensures that the instrumentation is OPERABLE shortly before PHYSICS TESTS begin and allows the operator to correct any instrumentation problems.

SR 3.1.9.2

Verification that the RCS lowest loop average temperature is ≥ 520ºF will ensure that the unit is operating in a condition consistent with the LCO requirements. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the conditions of the LCO are met.

SR 3.1.9.3

Verification that THERMAL POWER is ≤ 5% RTP ensures that an adequate margin is maintained between the THERMAL POWER level and the High Flux trip setpoint. Hourly verification is adequate for the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.9.3 (continued)

operator to determine any change in core conditions, such as xenon redistribution occurring after a THERMAL POWER reduction, that could cause THERMAL POWER to exceed the specified limit.

SR 3.1.9.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. CONTROL ROD position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Samarium concentration;

f. Xenon concentration;

g. Isothermal temperature coefficient (ITC), when below the point of adding heat (POAH);

h. Moderator defect, when above the POAH; and

i. Doppler defect, when above the POAH.

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical or critical but below the POAH, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

BASES

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50.59.
3. Regulatory Guide 1.68, Revision 2, August 1978.
4. UFSAR, Appendix 4B.
5. UFSAR, Section 14.1.
6. UFSAR, Tables 14.1-2 and 14.1-3.
7. UFSAR, Appendix 4B, Section 9.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Regulating Rod Insertion Limits

BASES

BACKGROUND

The insertion limits of the regulating rods are initial condition assumptions used in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect the core power distributions, the worth of a potential ejected rod, the assumptions of available SDM, and the initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are described in UFSAR, Appendices 3D.1.6, 3D.1.21, 3D.1.22, 3D.1.23, and 3D.1.24 (Ref. 1), and in 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Limits on regulating rod insertion are specified in the COLR, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are not violated.

The regulating rod groups operate with a predetermined amount of position overlap, to approximate a linear relation between rod worth and rod position (integral rod worth). To achieve this approximately linear relationship, the regulating rod groups are withdrawn and operated in a predetermined sequence. The automatic control system controls reactivity by moving the regulating rod groups in sequence within analyzed ranges. The group sequence and overlap limits are specified in the COLR.

The regulating rods are used for precise reactivity control of the reactor. The positions of the regulating rods are normally controlled automatically by the automatic control system but can also be controlled manually. They are capable of adding reactivity quickly compared with borating or diluting the Reactor Coolant System (RCS).

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that ensure that the criteria specified in 10 CFR 50.46 (Ref. 2) are not violated. Together, LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)," provide limits on control component operation and on

BASES

BACKGROUND (continued)

monitored process variables to ensure that the core operates within the F_Q and $F^N_{\Delta H}$ limits in the COLR. Operation within the F_Q limits given in the COLR prevents power peaks that would exceed the loss of coolant accident (LOCA) linear heat rate (LHR) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS). Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident. In addition to the F_Q and $F^N_{\Delta H}$ limits, certain reactivity limits are met by regulating rod insertion limits. The regulating rod insertion limits also restrict the ejected CONTROL ROD worth to the values assumed in the safety analysis and maintain the minimum required SDM in MODES 1 and 2.

This LCO is required to minimize fuel cladding failures that breach the primary fission product barrier and release fission products into the reactor coolant in the event of a LOCA, loss of flow accident, ejected rod accident, or other postulated accidents requiring termination by a Reactor Protection System trip function.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition 1) or anticipated operational occurrences (Condition 2). The LCOs governing regulating rod insertion, APSR position, AXIAL POWER IMBALANCE, and QPT preclude core power distributions that violate the following fuel design criteria:

a. During a LOCA, the peak cladding temperature must not exceed 2200°F (Ref. 2);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 3);

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm (Ref. 3); and

d. The CONTROL RODS must be capable of shutting down the reactor with a minimum required SDM with the highest worth CONTROL ROD stuck fully withdrawn (Ref. 1).

Fuel cladding damage does not occur when the core is operated outside the conditions of these LCOs during normal operation. However, fuel cladding damage could result if an accident occurs with the simultaneous violation of one or more of the LCOs limiting the regulating rod position,

BASES

APPLICABLE SAFETY ANALYSES (continued)

the APSR position, the AXIAL POWER IMBALANCE, and the QPT. This potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and correspondingly increased local LHRs.

The SDM requirement is met by limiting the regulating and safety rod insertion limits such that sufficient inserted reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes that the maximum worth rod remains fully withdrawn upon trip (Ref. 4). Operation at the SDM based regulating rod insertion limit may also indicate that the maximum ejected rod worth could be equal to the limiting value.

Operation beyond the regulating rod insertion limits may cause the local core power to approach the maximum linear heat generation rate or peaking factor with the allowed QPT present.

The regulating rod and safety rod insertion limits ensure that the safety analysis assumptions for SDM, ejected rod worth, and power distribution peaking factors remain valid (Refs. 3, 4, and 5).

The regulating rod insertion limits LCO satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on regulating rod sequence, including group overlap, and insertion positions as defined in the COLR, must be maintained because they ensure that the resulting power distribution is within the range of analyzed power distributions and that the SDM and ejected rod worth are maintained.

The overlap between regulating groups provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during regulating rod motion.

Error adjusted limits for regulating rod insertion are provided in the COLR. The limits are derived by an adjustment of the measurement system independent limits to allow for THERMAL POWER level uncertainty and rod position errors.

LCO 3.2.1 has been modified by a Note that suspends the LCO requirement for those regulating rods not within the limits of the COLR solely due to testing in accordance with SR 3.1.4.2, which verifies the freedom of the rods to move. This SR may require the regulating rods to move below the LCO limit, which would otherwise violate the LCO.

BASES

APPLICABILITY

The regulating rod sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2. These limits maintain the validity of the assumed power distribution, ejected rod worth, SDM, and reactivity insertion rate assumptions used in the safety analyses. Applicability in MODES 3, 4, and 5 is not required, because neither the power distribution nor ejected rod worth assumptions are exceeded in these MODES. SDM in MODES 3, 4, and 5 is governed by LCO 3.1.1, "SHUTDOWN MARGIN (SDM)."

ACTIONS

The regulating rod insertion limits provided in the COLR are based on both the initial conditions assumed in the accident analyses and on the SDM. Specifically, separate insertion limits are specified to determine whether the unit is operating in violation of the initial conditions (e.g., the range of power distributions) assumed in the accident analyses or whether the unit is in violation of the SDM or ejected rod worth limits. Separate insertion limits are provided because different Required Actions and Completion Times apply, depending on which insertion limit has been violated. The area between the boundaries of acceptable operation and unacceptable operation, illustrated on the regulating rod insertion limit figures in the COLR, is the restricted region. The actions required when operation occurs in the restricted region are described under Condition A. The actions required when operation occurs in the unacceptable region are described under Condition D. The actions required when operation occurs with the regulating rod group sequence or overlap limits not met are described under Condition C.

A.1

Operation with the regulating rods in the restricted region shown on the regulating rod insertion figures specified in the COLR potentially violates the LOCA LHR limits (F_Q limits), or the loss of flow accident DNB peaking limits ($F^N_{\Delta H}$ limits).

For verification that F_Q and $F^N_{\Delta H}$ are within their limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Verification that F_Q and $F^N_{\Delta H}$ are within their limits ensures that operation with the regulating rods inserted into the restricted operation region does not violate the ECCS or DNB criteria (Ref. 6). The required Completion Time of 2 hours is acceptable in that it allows the operator sufficient time for obtaining a power distribution map and for verifying the power peaking factors. Repeating SR 3.2.5.1 every 2 hours is acceptable because it ensures that continued verification of the power peaking factors is performed as core conditions (primarily regulating rod insertion and induced xenon redistribution) change.

BASES

ACTIONS

A.1 (continued)

Monitoring the power peaking factors F_Q and $F^N_{\Delta H}$ does not provide verification that the reactivity insertion rate on the rod trip or the ejected rod worth limit is maintained, because worth is a reactivity parameter rather than a power peaking parameter. However, if the COLR figures do not show that a rod insertion limit is ejected rod worth limited, then the ejected rod worth is no more limiting than the SDM based rod insertion limit in the core design (Ref. 7). Ejected rod worth limits are independently maintained by the Required Actions of Conditions A and D.

Required Action A.1 is modified by a Note that requires the performance of SR 3.2.5.1 only when THERMAL POWER is greater than 20% RTP. This establishes a Required Action that is consistent with the Applicability of LCO 3.2.5, "Power Peaking Factors."

A.2

Indefinite operation with the regulating rods inserted in the restricted region is not prudent. Even if power peaking monitoring per Required Action A.1 is continued, reactivity limits may not be met and the abnormal regulating rod insertion or group configuration may cause an adverse xenon redistribution, may cause the limits on AXIAL POWER IMBALANCE to be exceeded, or may adversely affect the long term fuel depletion pattern.

Therefore, restoration of the regulating rod groups to within limits is required within 24 hours after discovery of failure to meet the requirements of this LCO. This required Completion Time is reasonable based on the low probability of an event occurring simultaneously with the limit out of specification in this relatively short time period. In addition, it precludes long term depletion with abnormal group insertions or configurations, thereby limiting the potential for an adverse xenon redistribution.

B.1

If the regulating rods cannot be restored within the acceptable operation region shown on the figures in the COLR within the required Completion Time (i.e., Required Action A.2 not met), then the limit can be restored by reducing the THERMAL POWER to a value allowed by the regulating rod insertion limits in the COLR. The required Completion Time of 2 hours is sufficient to allow the operator to complete the power reduction in an

BASES

ACTIONS

B.1 (continued)

orderly manner and without challenging the plant systems. Operation for up to 2 hours more in the restricted operation region shown in the COLR is acceptable, based on the low probability of an event occurring simultaneously with the insertion limit out of specification in this relatively short time period. In addition, it precludes long term depletion with abnormal group insertions or configurations and limits the potential for an adverse xenon redistribution.

C.1 and C.2

Operation with the regulating rod groups out of sequence or with the group overlap limits exceeded may represent a condition beyond the assumptions used in the safety analyses, including SDM. The design calculations assume no deviation in nominal overlap between regulating rod groups. However, deviations as allowed by the COLR above or below the nominal overlap may be typical and would not cause significant differences in core reactivity, in power distribution, or in rod worth, relative to the design calculations. The group sequence must be maintained because design calculations assume the regulating rods withdraw and insert in a predetermined order.

For verification that F_Q and $F^N_{\Delta H}$ are within their limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Verification that F_Q and $F^N_{\Delta H}$ are within their limits ensures that operation with the regulating rods sequence or overlap limits not met does not violate the ECCS or DNB criteria (Ref. 6). The required Completion Time of 2 hours is acceptable in that it allows the operator sufficient time for obtaining a power distribution map and for verifying the power peaking factors. Required Action C.1 is modified by a Note that requires the performance of SR 3.2.5.1 only when THERMAL POWER is greater than 20% RTP. This establishes a Required Action that is consistent with the Applicability of LCO 3.2.5.

Indefinite operation with the regulating rods sequence or overlap limits not met is not prudent because of the potential severity associated with gross violations of group sequence or overlap requirements. Therefore, the regulating rod groups must be restored to within the sequence and overlap limits within 4 hours. The 4 hour Completion Time is based on operating experience which supports the restoration time without unnecessarily challenging unit operation and the low probability of an event occurring simultaneously with the limit out of specification.

BASES

ACTIONS (continued)

D.1

Operation in the unacceptable operation region shown on the figures in the COLR corresponds to power operation with an SDM less than the minimum required value or with the ejected rod worth greater than the allowable value. The regulating rods may be inserted too far to provide sufficient negative reactivity insertion following a reactor trip and the ejected rod worth may exceed its initial condition limit. Therefore, the RCS boron concentration must be increased to restore the regulating rod insertion to a value that preserves the SDM and ejected rod worth limits. The RCS boration must occur as described in the Bases of LCO 3.1.1. The required Completion Time of 15 minutes to initiate boration is reasonable, based on limiting the potential xenon redistribution, the low probability of an accident occurring in this relatively short time period, and the number of steps required to complete this Action. This period allows the operator sufficient time for aligning the required valves and for starting the boric acid pumps. Boration continues until the regulating rod group positions are restored to at least within the restricted operational region, which restores the minimum SDM capability and reduces the potential ejected rod worth to within its limit.

D.2.1

The required Completion Time of 2 hours from initial discovery of a regulating rod group in the unacceptable operation region until its restoration to within the restricted operation region shown on the figures in the COLR allows sufficient time for borated water to enter the RCS from the chemical addition and makeup systems, thereby allowing the regulating rods to be withdrawn to the restricted region. Operation in the unacceptable operation region for 2 hours is reasonable, based on limiting the potential for an adverse xenon redistribution, the low probability of an accident occurring in this relatively short time period, and the number of steps required to complete this Action.

D.2.2

The SDM and ejected rod worth limit can also be restored by reducing the THERMAL POWER to a value allowed by the regulating rod insertion limits in the COLR. The required Completion Time of 2 hours is sufficient to allow the operator to complete the power reduction in an orderly manner and without challenging the plant systems. Operation for up to 2 hours in the unacceptable operation region shown in the COLR is acceptable, based on the low probability of an event occurring

BASES

ACTIONS

D.2.2 (continued)

simultaneously with the limit out of specification in this relatively short time period. In addition, it precludes long term depletion with abnormal group insertions or configurations and limits the potential for an adverse xenon redistribution.

E.1

If any Required Action and associated Completion Time of Condition C or D is not met, then the reactor is placed in MODE 3, in which this LCO does not apply. This Action ensures that the reactor does not continue operating in violation of the peaking limits, the ejected rod worth, the reactivity insertion rate assumed as initial conditions in the accident analyses, or the required minimum SDM assumed in the accident analyses. The required Completion Time of 6 hours is reasonable, based on operating experience regarding the amount of time required to reach MODE 3 from RTP without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

This Surveillance ensures that the sequence and overlap limits are not violated. A Surveillance Frequency of 12 hours is acceptable because little rod motion occurs in 12 hours due to fuel burnup. Also, the Frequency takes into account other information available in the control room for monitoring the status of the regulating rods.

SR 3.2.1.2

Verification of the regulating rod insertion limits as specified in the COLR at a Frequency of 12 hours is sufficient to detect regulating rod groups that may be approaching the group insertion limits, because little rod motion due to fuel burnup occurs in 12 hours. Also, the Frequency takes into account other information available in the control room for monitoring the status of the regulating rods.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.3

Within 4 hours prior to achieving criticality, an estimated critical position for the CONTROL RODS is determined. Verification that SDM meets the minimum requirements ensures that sufficient SDM capability exists with the CONTROL RODS at the estimated critical position if it is necessary to shut down or trip the reactor after criticality. The Frequency of 4 hours prior to criticality provides sufficient time to verify SDM capability and establish the estimated critical position.

REFERENCES

1. UFSAR, Appendices 3D.1.6, Criterion 10 – Reactor Design; 3D.1.21, Criterion 25 – Protection System Requirements For Reactivity Control Malfunctions; 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability; 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability; and 3D.1.24, Criterion 28 – Reactivity Limits.

2. 10 CFR 50.46.

3. UFSAR, Section 15.4.3.

4. UFSAR, Section 15.1.2.

5. UFSAR, Section 15.2.3.

6. BAW-10179P-A, "Safety Criteria and Methodology for Acceptance Cycle Reload Analyses" (revision specified in Specification 5.6.3).

7. BAW-10122P-A, "Normal Operating Controls" (revision specified in Specification 5.6.3).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 AXIAL POWER SHAPING ROD (APSR) Insertion Limits

BASES

BACKGROUND

The insertion limits of the APSRs are initial condition assumptions in all safety analyses that are affected by core power distributions. The applicable criterion for these power distribution design requirements are UFSAR, Appendices 3D.1.6 and 3D.1.22 (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Limits on APSR insertion are specified in the COLR, and all APSR positions are monitored and controlled during power operation to ensure that the power distribution defined by the design power peaking limits is maintained.

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that meet the criteria specified in Reference 2. Together, LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)," provide limits on control component operation and on monitored process variables to ensure that the core operates within the F_Q and $F^N_{\Delta H}$ limits in the COLR. Operation within the F_Q limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) linear heat rate (LHR) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS). Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident. The APSRs are not required for reactivity insertion rate on trip or SDM and, therefore, they do not trip upon a reactor trip.

This LCO is required to minimize fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a LOCA, loss of flow accident, ejected rod accident, or other postulated accident requiring termination by a Reactor Protection System trip function.

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition 1) or anticipated operational occurrences (Condition 2). Acceptance criteria for the safety and regulating rod insertion, APSR position, AXIAL POWER IMBALANCE, and QPT LCOs preclude core power distributions that violate the following fuel design criteria:

a. During a LOCA, the peak cladding temperature must not exceed 2200°F (Ref. 2);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 1);

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm (Ref. 3); and

d. CONTROL RODS must be capable of shutting down the reactor with a minimum required SDM with the highest worth CONTROL ROD stuck fully withdrawn (Ref. 4).

Fuel cladding damage does not occur when the core is operated outside these LCOs during normal operation. However, fuel cladding damage could result should an accident occur simultaneously with violation of one or more of these LCOs. This potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and corresponding increased local LHRs.

Operation at the APSR insertion limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPT present.

The APSR insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on APSR physical insertion as defined in the COLR must be maintained because they serve the function of controlling the power distribution within an acceptable range.

The fuel cycle design assumes APSR withdrawal at the effective full power days (EFPD) burnup window specified in the COLR. Prior to this window, the APSRs are maintained in accordance with the rod operation recommendations. After this window, the APSRs are not allowed to be reinserted for the remainder of the fuel cycle.

BASES

LCO (continued)

Error adjusted limits for APSR insertion are provided in the COLR. The limits are derived by adjustment of the measurement system independent limits to allow for THERMAL POWER level uncertainty and rod position errors.

APPLICABILITY

The APSR physical insertion limits shall be maintained with the reactor in MODES 1 and 2. These limits maintain the power distribution within the range assumed in the accident analyses. Applicability in MODES 3, 4, and 5 is not required, because the power distribution assumptions in the accident analyses would not be exceeded in these MODES.

ACTIONS

For steady state power operation, a normal position for APSR insertion is specified in the rod operation recommendations. The APSRs may be positioned as necessary for transient AXIAL POWER IMBALANCE control until the fuel cycle design requires them to be fully withdrawn. (Not all fuel cycles may incorporate APSR withdrawal.) APSR insertion limits are not imposed for gray APSRs, with two exceptions. If the fuel cycle design incorporates an APSR withdrawal (usually near end of cycle (EOC)), the APSRs are positioned as allowed in the rod operation recommendations before the withdrawal occurs. Conversely, after the fuel cycle burnup for the APSR withdrawal occurs, the APSRs may not be reinserted for the remainder of the fuel cycle. These restrictions apply to ensure the axial burnup distribution that accumulates in the fuel will be consistent with the expected (as designed) distribution.

A.1

For verification that the core parameters F_Q and $F^N_{\Delta H}$ are within their limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Successful verification that F_Q and $F^N_{\Delta H}$ are within their limits ensures that operation with the APSRs inserted or withdrawn in violation of the times specified in the COLR do not violate either the ECCS or DNB criteria (Ref. 5). The required Completion Time of 2 hours is reasonable to allow the operator to obtain a power distribution map and to verify the power peaking factors. Repeating SR 3.2.5.1 every 2 hours is reasonable to ensure that continued verification of the power peaking factors is obtained as core conditions (primarily the regulating rod insertion and induced xenon redistribution) change.

Required Action A.1 is modified by a Note that requires the performance of SR 3.2.5.1 only when THERMAL POWER is greater than 20% RTP. This establishes a Required Action that is consistent with the Applicability of LCO 3.2.5, "Power Peaking Factors."

BASES

ACTIONS (continued)

A.2

Indefinite operation with the APSRs inserted or withdrawn in violation of the times specified in the COLR is not prudent. Even if power peaking monitoring per Required Action A.1 is continued, the abnormal APSR insertion or withdrawal may cause an adverse xenon redistribution, may cause the limits on AXIAL POWER IMBALANCE to be exceeded, or may affect the long term fuel depletion pattern. Therefore, power peaking monitoring is allowed for up to 24 hours. This required Completion Time is reasonable based on the low probability of an event occurring simultaneously with the APSR limit out of specification. In addition, it precludes long term depletion with the APSRs in positions that have not been analyzed, thereby limiting the potential for an adverse xenon redistribution. This time limit also ensures that the intended burnup distribution is maintained, and allows the operator sufficient time to reposition the APSRs to correct their positions.

Because the APSRs are not operated by the automatic control system, manual action by the operator is required to restore the APSRs to the positions specified in the COLR.

B.1

If any Required Action and associated Completion Time is not met, the reactor must be placed in MODE 3, in which this LCO does not apply. This action ensures that the fuel does not continue to be depleted in an unintended burnup distribution. The required Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 3 from RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

Fuel cycle designs that allow APSR withdrawal near EOC do not permit reinsertion of APSRs after the time of withdrawal. Verification that the APSRs are within their insertion limits at a 12 hour Frequency is sufficient to ensure that the APSR insertion limits are preserved. The 12 hour Frequency required for performing this verification is sufficient because APSRs are positioned by manual control and are normally moved infrequently. The Frequency takes into account other information available in the control room for monitoring the axial power distribution in the reactor core.

BASES

REFERENCES

1. UFSAR, Appendices 3D.1.6, Criterion 10 – Reactor Design and 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability.

2. 10 CFR 50.46.

3. UFSAR, Section 15.4.3.

4. UFSAR, Appendix 3D.1.23.

5. BAW-10179P-A, "Safety Criteria and Methodology for Acceptance Cycle Reload Analyses" (revision specified in Specification 5.6.3).

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL POWER IMBALANCE Operating Limits

BASES

BACKGROUND

This LCO is required to limit the core power distribution based on accident initial condition criteria.

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that satisfy the criteria specified in 10 CFR 50.46 (Ref. 1). This LCO provides limits on AXIAL POWER IMBALANCE to ensure that the core operates within the F_Q and $F^N_{\Delta H}$ limits given in the COLR. Operation within the F_Q limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) linear heat rate (LHR) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS). Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident.

This LCO is required to limit fuel cladding failures that breach the primary fission product barrier and release fission products into the reactor coolant in the event of a LOCA, loss of forced reactor coolant flow accident, or other postulated accident requiring termination by a Reactor Protection System trip function. This LCO limits the amount of damage to the fuel cladding during an accident by maintaining the validity of the assumptions in the safety analyses related to the initial power distribution and reactivity.

Fuel cladding failure during a postulated LOCA is limited by restricting the maximum linear heat rate (LHR) so that the peak cladding temperature does not exceed 2200°F (Ref. 2). Peak cladding temperatures > 2200°F cause severe cladding failure by oxidation due to a Zircaloy water reaction. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, peak cladding temperature is usually most limiting.

Proximity to the DNB condition is expressed by the departure from nucleate boiling ratio (DNBR), defined as the ratio of the cladding surface heat flux required to cause DNB to the actual cladding surface heat flux. The minimum DNBR value during both normal operation and anticipated transients is limited to the DNBR correlation limit for the particular fuel design in use and is accepted as an appropriate margin to DNB. The DNB correlation limit ensures that there is at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB.

BASES

BACKGROUND (continued)

The measurement system independent limits on AXIAL POWER IMBALANCE are determined directly by the reload safety evaluation analysis without adjustment for measurement system error and uncertainty. Operation beyond these limits could invalidate the assumptions used in the accident analyses regarding the core power distribution.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition 1) and anticipated operational occurrences (Condition 2). The LCOs based on power distribution, LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)," preclude core power distributions that would violate the following fuel design criteria:

a. During a LOCA, peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least a 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm (Ref. 3); and

d. The CONTROL RODS must be capable of shutting down the reactor with a minimum required SDM with the highest worth CONTROL ROD stuck fully withdrawn (Ref. 4).

The regulating rod positions, the APSR positions, the AXIAL POWER IMBALANCE, and the QPT are process variables that characterize and control the three dimensional power distribution of the reactor core.

Fuel cladding damage does not occur when the core is operated outside this LCO during normal operation. However, fuel cladding damage could result should an accident occur with simultaneous violation of one or more of the LCOs governing the four process variables cited above. This potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and corresponding increased local LHRs.

The regulating rod insertion, the APSR positions, the AXIAL POWER IMBALANCE, and the QPT are monitored and controlled during power operation to ensure that the power distribution is within the bounds set by

BASES

APPLICABLE SAFETY ANALYSES (continued)

the safety analyses. The axial power distribution is maintained primarily by the AXIAL POWER IMBALANCE and the APSR insertion limits; and the radial power distribution is maintained primarily by the QPT limits. The regulating rod insertion limits affect both the radial and axial power distributions.

The dependence of the core power distribution on burnup, regulating rod insertion, APSR position, and spatial xenon distribution is taken into account when the reload safety evaluation analysis is performed.

Operation at the AXIAL POWER IMBALANCE limit must be interpreted as operating the core at the maximum allowable F_Q or $F^N_{\Delta H}$ peaking factors assumed as initial conditions for the accident analyses with the allowed QPT present.

AXIAL POWER IMBALANCE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The power distribution LCO limits have been established based on correlations between power peaking and easily measured process variables: regulating rod position, APSR position, AXIAL POWER IMBALANCE, and QPT. The AXIAL POWER IMBALANCE envelope contained in the COLR represents the limits for which the core power distribution would either exceed the LOCA LHR limits or cause a reduction in the DNBR below the Safety Limit during the loss of flow accident with the allowable QPT present and with the APSR positions consistent with the limitations on APSR withdrawal determined by the fuel cycle design and specified by LCO 3.2.2.

The AXIAL POWER IMBALANCE limits (measurement system dependent limits) applicable for the Incore Detector System and the Excore Detector System are provided in the COLR.

APPLICABILITY

In MODE 1, the limits on AXIAL POWER IMBALANCE must be maintained when THERMAL POWER is > 40% RTP to prevent the core power distribution from exceeding the LOCA and loss of flow assumptions used in the accident analyses. Applicability of these limits at < 40% RTP in MODE 1 is not required. This operation is acceptable because the combination of AXIAL POWER IMBALANCE with the maximum allowable THERMAL POWER level will not result in LHRs sufficiently large to violate the fuel design limits. In MODES 2, 3, 4, 5, and 6, this LCO is not applicable because the reactor is not generating sufficient THERMAL POWER to produce fuel damage.

BASES

APPLICABILITY (continued)

In MODE 1, it may be necessary to suspend the AXIAL POWER IMBALANCE limits during PHYSICS TESTS per LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 1." Suspension of these limits is permissible because the reactor protection criteria are maintained by the remaining LCOs governing the three dimensional power distribution and by the Surveillances required by LCO 3.1.8.

ACTIONS

A.1

The AXIAL POWER IMBALANCE operating limits that maintain the validity of the assumptions regarding the power distributions in the accident analyses of the LOCA and the loss of flow accident are provided in the COLR. Operation within the AXIAL POWER IMBALANCE limits given in the COLR is the acceptable region of operation. Operation in violation of the AXIAL POWER IMBALANCE limits given in the COLR is the restricted region of operation.

Operation with AXIAL POWER IMBALANCE in the restricted region shown on the AXIAL POWER IMBALANCE figures in the COLR potentially violates the LOCA LHR limits (F_Q limits) or the loss of flow accident DNB peaking limits $F^N_{\Delta H}$ limits) or both. For verification that F_Q and $F^N_{\Delta H}$ are within their specified limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Verification that F_Q and $F^N_{\Delta H}$ are within their specified limits ensures that operation with the AXIAL POWER IMBALANCE in the restricted region does not violate the ECCS or 95/95 DNB criteria. The required Completion Time of 2 hours provides reasonable time for the operator to obtain a power distribution map and to determine and verify that the power peaking factors are within their specified limits. The 2 hour Frequency provides reasonable time to ensure that continued verification of the power peaking factors is obtained as core conditions (primarily regulating rod insertion and induced xenon redistribution) change, because little rod motion occurs in 2 hours due to fuel burnup, the potential for xenon redistribution is limited, and the probability of an event occurring in this short time frame is low.

A.2

Indefinite operation with the AXIAL POWER IMBALANCE in the restricted region is not prudent. Even if power peaking monitoring per Required Action A.1 is continued, excessive AXIAL POWER IMBALANCE over an extended period of time may cause a potentially adverse xenon

BASES

ACTIONS

A.2 (continued)

redistribution to occur. Therefore, power peaking monitoring is only allowed for a maximum of 24 hours. This required Completion Time is reasonable based on the low probability of a limiting event occurring simultaneously with the AXIAL POWER IMBALANCE outside the limits of this LCO. In addition, this limited Completion Time precludes long term depletion of the reactor fuel with excessive AXIAL POWER IMBALANCE and gives the operator sufficient time to reposition the APSRs or regulating rods to reduce the AXIAL POWER IMBALANCE because adverse effects of xenon redistribution and fuel depletion are limited.

B.1

If any Required Action and associated Completion Time is not met, the AXIAL POWER IMBALANCE may exceed its specified limits and the reactor may be operating with a global axial power distribution mismatch. Continued operation in this configuration may induce an axial xenon oscillation and may result in an increased linear heat generation rate when the xenon redistributes. Reducing THERMAL POWER to ≤ 40% RTP reduces the maximum LHR to a value that does not exceed the F_Q and $F^N_{\Delta H}$ initial condition limits assumed in the accident analyses. The required Completion Time of 2 hours is reasonable based on limiting a potentially adverse xenon redistribution, the low probability of an accident occurring in this relatively short time period, and the number of steps required to complete this Action.

SURVEILLANCE REQUIREMENTS

The AXIAL POWER IMBALANCE can be monitored by both the Incore and Excore Detector Systems. The AXIAL POWER IMBALANCE maximum allowable limits are derived from their corresponding measurement system independent limits by adjusting for both the system observability errors and instrumentation errors. Although they may be based on the same measurement system independent limits, the setpoints for the different systems are not identical because of differences in the errors applicable for each of these systems. The uncertainty analysis that defines the required error adjustment to convert the measurement system independent limits to maximum allowable limits assumes that 75% of the incore detectors in each quadrant are OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.3.1

Verification of the AXIAL POWER IMBALANCE indication every 12 hours ensures that the AXIAL POWER IMBALANCE limits are not violated and takes into account other information available to the operator in the control room. This Surveillance Frequency is acceptable because the mechanisms that can cause AXIAL POWER IMBALANCE, such as xenon redistribution or CONTROL ROD drive mechanism malfunctions that cause slow AXIAL POWER IMBALANCE increases, can be discovered by the operator before the specified limits are violated.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 6.3
3. UFSAR, Section 15.4.3.
4. UFSAR, Appendix 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT (QPT)

BASES

BACKGROUND

This LCO is required to limit the core power distribution based on accident initial condition criteria.

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that preserve the criteria specified in 10 CFR 50.46 (Ref. 1). Together, LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)," provide limits on control component operation and on monitored process variables to ensure that the core operates within the F_Q and $F^N_{\Delta H}$ limits given in the COLR. Operation within the F_Q limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) linear heat rate (LHR) limits derived by Emergency Core Cooling Systems (ECCS) analysis. Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident.

This LCO is required to limit fuel cladding failures that breach the primary fission product barrier and release fission products to the reactor coolant in the event of a LOCA, loss of forced reactor coolant flow, or other accident requiring termination by a Reactor Protection System trip function. This LCO limits the amount of damage to the fuel cladding during an accident by maintaining the validity of the assumptions used in the safety analysis related to the initial power distribution and reactivity.

Fuel cladding failure during a postulated LOCA is limited by restricting the maximum linear heat rate (LHR) so that the peak cladding temperature does not exceed 2200°F (Ref. 2). Peak cladding temperatures > 2200°F cause severe cladding failure by oxidation due to a Zircaloy water reaction. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, peak cladding temperature is usually most limiting.

Proximity to the DNB condition is expressed by the departure from nucleate boiling ratio (DNBR), defined as the ratio of the cladding surface heat flux required to cause DNB to the actual cladding surface heat flux. The minimum DNBR value during both normal operation and anticipated

BASES

BACKGROUND (continued)

transients is limited to the DNBR correlation limit for the particular fuel design in use, and is accepted as an appropriate margin to DNB. The DNBR correlation limit ensures that there is at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB.

The measurement system independent limits on QPT are determined directly by the reload safety evaluation analysis without adjustment for measurement system error and uncertainty. Operation beyond these limits could invalidate core power distribution assumptions used in the accident analysis. The error adjusted maximum allowable limits (measurement system dependent limits) for QPT are specified in the COLR.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition 1) and anticipated operational occurrences (Condition 2). The LCOs based on power distribution (LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, and LCO 3.2.4) preclude core power distributions that violate the following fuel design criteria:

a. During a LOCA, the peak cladding temperature must not exceed 2200°F (Ref. 2);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the fission energy input to the fuel must not exceed 280 cal/gm (Ref. 3); and

d. The CONTROL RODS must be capable of shutting down the reactor with a minimum required SDM with the highest worth CONTROL ROD stuck fully withdrawn (Ref. 4).

QPT is one of the process variables that characterize and control the three dimensional power distribution of the reactor core.

Fuel cladding damage does not occur when the core is operated outside this LCO during normal operation. However, fuel cladding damage could result if an accident occurs with simultaneous violation of one or more of the LCOs governing the core power distribution. Changes in the power distribution can cause increased power peaking and correspondingly increased local LHRs.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The dependence of the core power distribution on burnup, regulating rod insertion, APSR position, and spatial xenon distribution is taken into account during the reload safety evaluation analysis. An allowance for QPT is accommodated in the analysis and resultant LCO limits. The increase in peaking taken for QPT is developed from a database of full core power distribution calculations (Ref. 5). The calculations consist of simulations of many power distributions with tilt causing mechanisms (e.g., dropped or misaligned CONTROL RODS, broken APSR fingers fully inserted, misloaded assemblies, and burnup gradients). An increase of < 2% peak power per 1% QPT is supported by the analysis, therefore a value of 2% peak power increase per 1% QPT is used to bound peak power increases due to QPT.

Operation at the AXIAL POWER IMBALANCE or rod insertion limits must be interpreted as operating the core at the maximum allowable F_Q or $F^N_{\Delta H}$ peaking factors for accident initial conditions with the allowed QPT present.

QPT satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The power distribution LCO limits have been established based on correlations between power peaking and easily measured process variables: regulating rod position, APSR position, AXIAL POWER IMBALANCE, and QPT. The regulating rod insertion limits and the AXIAL POWER IMBALANCE boundaries contained in the COLR represent the measurement system independent limits at which the core power distribution either exceeds the LOCA LHR limits or causes a reduction in DNBR below the safety limit during a loss of flow accident with the allowable QPT present and with an APSR position consistent with the limitations on APSR withdrawal determined by the fuel cycle design and specified by LCO 3.2.2.

The steady state, transient, and maximum limits for QPT applicable for the Incore Detector System are provided in the COLR. The limits for the Incore Detector System are derived by adjustment of the measurement system independent QPT limits to allow for system observability and instrumentation errors.

APPLICABILITY

In MODE 1, the limits on QPT must be maintained when THERMAL POWER is > 20% RTP to prevent the core power distribution from exceeding the design limits. The minimum power level of 20% RTP is large enough to obtain meaningful QPT indications without compromising safety. Operation at or below 20% RTP with QPT up to 20% is acceptable because the resulting maximum LHR is not high enough to

BASES

APPLICABILITY (continued)

cause violation of the LOCA LHR limit (F_Q limit) or the initial condition DNB allowable peaking limit ($F^N_{\Delta H}$ limit) during accidents initiated from this power level.

In MODE 2, the combination of QPT with maximum ALLOWABLE THERMAL POWER level does not result in LHRs sufficiently large to violate the fuel design limits, and therefore, applicability in this MODE is not required. Although not specifically addressed in the LCO, QPTs > 20% in MODE 1 with THERMAL POWER < 20% RTP are allowed for the same reason.

In MODES 3, 4, 5, and 6, this LCO is not applicable, because the reactor is not generating THERMAL POWER and QPT is indeterminate.

In MODE 1, it may be necessary to suspend the QPT limits during PHYSICS TESTS per LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 1." Suspension of these limits is permissible because the reactor protection criteria are maintained by the remaining LCOs governing the three dimensional power distribution and by the Surveillances required by LCO 3.1.8.

ACTIONS

A.1.1

The steady state limit specified in the COLR provides an allowance for QPT that may occur during normal operation. A peaking increase to accommodate QPTs up to the steady state limit is allowed by the regulating rod insertion limits of LCO 3.2.1 and the AXIAL POWER IMBALANCE limits of LCO 3.2.3.

Operation with QPT greater than the steady state limit specified in the COLR potentially violates the LOCA LHR limits (F_Q limits), or loss of flow accident DNB peaking limits ($F^N_{\Delta H}$ limits), or both. For verification that F_Q and $F^N_{\Delta H}$ are within their specified limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Verification that F_Q and $F^N_{\Delta H}$ are within their limits ensures that operation with QPT greater than the steady state limit does not violate the ECCS or 95/95 DNB criteria. The required Completion Time of once per 2 hours is a reasonable amount of time to allow the operator to obtain a power distribution map and to verify the power peaking factors. Repeating SR 3.2.5.1 every 2 hours is a reasonable Frequency at which to ensure that continued verification of the power peaking factors is obtained as core conditions that influence QPT change.

BASES

ACTIONS (continued)

A.1.2.1

The safety analysis has shown that a conservative corrective action is to reduce THERMAL POWER by 2% RTP or more from the ALLOWABLE THERMAL POWER for each 1% of QPT in excess of the steady state limit. This action limits the local LHR to a value corresponding to steady state operation, thereby reducing it to a value within the assumed accident initial condition limits. The required Completion Time of 2 hours is reasonable, based on limiting the potential for xenon redistribution, the low probability of an accident occurring, and the steps required to complete the Required Action.

If QPT can be reduced to less than or equal to the steady state limit in < 2 hours, the reactor may return to normal operation without undergoing a power reduction. Significant radial xenon redistribution does not occur within this amount of time.

The required Completion Time of 2 hours after the last performance of SR 3.2.5.1 allows reduction of THERMAL POWER in the event the operators cannot or choose not to continue to perform SR 3.2.5.1 as required by Required Action A.1.1.

A.1.2.2

Power operation is allowed to continue if THERMAL POWER is reduced in accordance with Required Action A.1.2.1. The same reduction (i.e., 2% RTP or more) is also applicable to the High Flux trip setpoint and the Flux-ΔFlux-Flow trip setpoint, for each 1% of QPT in excess of the steady state limit. This reduction maintains both core protection and an OPERABILITY margin at the reduced THERMAL POWER level similar to that at RTP. The required Completion Time of 10 hours is reasonable based on the need to limit the potentially adverse xenon redistribution, the low probability of an accident occurring while operating out of specification, and the number of steps required to complete the Required Action.

A.2

Although the actions directed by Required Action A.1.2.1 restore margins, if the source of the QPT is not established and corrected, it is prudent to establish increased margins. A required Completion Time of 24 hours from discovery of failure to meet the LCO to reduce QPT to less than the steady state limit is a reasonable time for investigation and corrective measures.

BASES

ACTIONS (continued)

B.1

If QPT exceeds the transient limit but is equal to or less than the maximum limit due to a misaligned CONTROL ROD or APSR, then power operation is allowed to continue if the THERMAL POWER is reduced 2% RTP or more from the ALLOWABLE THERMAL POWER for each 1% of QPT in excess of the steady state limit. Thus, the maximum limit is the upper bound within which the 2% for 1% power reduction rule may be applied, but only for QPTs caused by CONTROL ROD or APSR misalignment. The required Completion Time of 30 minutes ensures that the operator completes the THERMAL POWER reduction before significant xenon redistribution occurs.

B.2

When a misaligned CONTROL ROD or APSR occurs, a local xenon redistribution may occur. The required Completion Time of 2 hours allows the operator sufficient time to relatch or realign a CONTROL ROD or APSR, but is short enough to limit xenon redistribution so that large increases in the local LHR do not occur due to xenon redistribution resulting from the QPT.

C.1

If any Required Action and associated Completion Time of Condition A or B is not met or if QPT is greater than the transient limit and less than or equal to the maximum limit due to causes other than misalignment of a CONTROL ROD or an APSR, a further power reduction is required. Power reduction to < 60% RTP provides conservative protection from increased peaking due to xenon redistribution. Power reduction to 60% of the ALLOWABLE THERMAL POWER is a conservative method of limiting the maximum core LHR for QPTs up to the maximum limit. Although the power reduction is based on the correlation used in Required Actions A.1.2.1 and B.1, the database for a power peaking increase as a function of QPT is less extensive for tilt mechanisms other than misaligned CONTROL RODS and APSRs. Because greater uncertainty in the potential power peaking increase exists with the less extensive database, a more conservative action is taken when the tilt is caused by a mechanism other than a misaligned CONTROL ROD or APSR. The required Completion Time of 2 hours is reasonable to allow the operator to reduce THERMAL POWER to < 60% of ALLOWABLE THERMAL POWER without challenging plant systems.

BASES

ACTIONS (continued)

C.2

Reduction of the High Flux trip setpoint to ≤ 65.5% of ALLOWABLE THERMAL POWER after THERMAL POWER has been reduced to < 60% of ALLOWABLE THERMAL POWER maintains both core protection and OPERABILITY margin at reduced power similar to that at full power. The required Completion Time of 10 hours allows the operator sufficient time to reset the trip setpoint and is reasonable based on the number of steps required to complete the Required Action.

D.1

If any Required Action and associated Completion Time of Condition C is not met or if QPT is greater than the maximum limit, the reactor must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 20% RTP within 2 hours. Operation at 20% RTP allows the operator to investigate the cause of the QPT and to correct it. Local LHRs with a large QPT do not violate the fuel design limits at or below 20% RTP. The maximum limit specified in the COLR is set as the upper bound within which power reduction to 60% of ALLOWABLE THERMAL POWER or power reduction of 2% from ALLOWABLE THERMAL POWER for each 1% of QPT (for misaligned CONTROL RODS only) applies (Ref. 5). The maximum limit specified in the COLR is consistent with allowing power operation up to 60% of ALLOWABLE THERMAL POWER when QPT setpoints are exceeded. QPT in excess of the maximum limit can be an indication of a severe power distribution anomaly, and a power reduction to at most 20% RTP ensures local LHRs do not exceed allowable limits while the cause is being determined and corrected. The required Completion Time of 2 hours is acceptable based on limiting the potential increase in local LHRs that could occur due to xenon redistribution with the QPT out of specification.

SURVEILLANCE REQUIREMENTS

QPT can be monitored by the Incore Detector System. The QPT limits are derived from the Incore Detector System independent limits by adjustment for system observability errors and instrumentation errors. For QPT measurements using the Incore Detector System, the minimum OPERABLE detectors consists of 75% of the detectors per quadrant.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.4.1

Checking the QPT indication every 7 days ensures that the operator can determine whether the plant computer software and Incore Detector System inputs for monitoring QPT are functioning properly and takes into account other information available to the operator in the control room. This procedure allows the QPT mechanisms, such as xenon redistribution, burnup gradients, and CONTROL ROD drive mechanism malfunctions, which can cause slow development of a QPT, to be detected. Operating experience has confirmed the acceptability of a Surveillance Frequency of 7 days.

Following restoration of the QPT to within the steady state limit, operation at ≥ 95% RTP may proceed provided the QPT is determined to remain within the steady state limit at the increased THERMAL POWER level. In case QPT exceeds the steady state limit for more than 24 hours or exceeds the transient limit (Condition A or B), the potential for xenon redistribution is greater. Therefore, the QPT is monitored once every hour for 12 hours to determine whether the period of any oscillation due to xenon redistribution causes the QPT to exceed the steady state limit again.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 6.3.
3. UFSAR, Section 15.4.3.
4. UFSAR, Appendix 3D.1.23, Criterion 27 – Combined Reactivity Control Systems Capability.
5. BAW 10122A, Rev. 1, May 1984.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.5 Power Peaking Factors

BASES

BACKGROUND

The purpose of this LCO is to establish limits that constrain the core power distribution within design limits during normal operation (Condition 1) and during anticipated operational occurrences (Condition 2) such that accident initial condition protection criteria are preserved. The accident initial condition criteria are preserved by bounding operation at THERMAL POWER within specified acceptable fuel design limits.

F_Q is a specified acceptable fuel design limit that preserves the initial conditions for the Emergency Core Cooling Systems (ECCS) analysis. F_Q is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod dimensions. Because F_Q is a ratio of local power densities, it is related to the maximum local (pellet) power density in a fuel rod. Operation within the F_Q limits given in the COLR prevents power peaking that would exceed the loss of coolant accident (LOCA) linear heat rate (LHR) limits derived from the analysis of the ECCS.

The $F^N_{\Delta H}$ limit is a specified acceptable fuel design limit that preserves the initial conditions for the limiting loss of flow transient. $F^N_{\Delta H}$ is defined as the ratio of the integral of linear power along the fuel rod on which the minimum departure from nucleate boiling ratio (DNBR) occurs to the average integrated rod power. Because $F^N_{\Delta H}$ is a ratio of integrated powers, it is related to the maximum total power produced in a fuel rod. Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a postulated loss of forced reactor coolant flow accident.

Measurement of the core power peaking factors using the Incore Detector System to obtain a three dimensional power distribution map provides direct confirmation that F_Q and $F^N_{\Delta H}$ are within their limits, and may be used to verify that the power peaking factors remain bounded when one or more normal operating parameters exceed their limits.

BASES

APPLICABLE SAFETY ANALYSES

The limits on F_Q are determined by the ECCS analysis in order to limit peak cladding temperatures to 2200°F during a LOCA. The maximum acceptable cladding temperature is specified by 10 CFR 50.46 (Ref. 1). Higher cladding temperatures could cause severe cladding failure by oxidation due to a Zircaloy water reaction. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, peak cladding temperature is usually most limiting.

The limits on $F^N_{\Delta H}$ provide protection from DNB during a limiting loss of flow transient. Proximity to the DNB condition is expressed by the DNBR, defined as the ratio of the cladding surface heat flux required to cause DNB to the actual cladding surface heat flux. The minimum DNBR value during both normal operation and anticipated transients is limited to the DNBR correlation limit for the particular fuel design in use, and is accepted as an appropriate margin to DNB. The DNBR correlation limit ensures that there is at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB.

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a LOCA, peak cladding temperature must not exceed 2200°F (Ref. 1); and

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition.

The reload safety evaluation analysis determines limits on global core parameters that characterize the core power distribution. The primary parameters used to monitor and control the core power distribution are the regulating rod position, the APSR position, the AXIAL POWER IMBALANCE, and the QPT. These parameters are normally used to monitor and control the core power distribution because their measurements are continuously observable. Limits are placed on these parameters to ensure that the core power peaking factors remain bounded during operation in MODE 1 with THERMAL POWER greater than 20% RTP. Nuclear design model calculational uncertainty, manufacturing tolerances (e.g., the engineering hot channel factor), effects of fuel densification and rod bow, and modeling simplifications (such as treatment of the spacer grid effects) are accommodated through use of peaking augmentation factors in the reload safety evaluation analysis.

BASES

APPLICABLE SAFETY ANALYSES (continued)

F_Q and $F^N_{\Delta H}$ satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO for the power peaking factors F_Q and $F^N_{\Delta H}$ ensures that the core operates within the bounds assumed for the ECCS and thermal hydraulic analyses. Verification that F_Q and $F^N_{\Delta H}$ are within the limits of this LCO as specified in the COLR allows continued operation at THERMAL POWER when the Required Actions of LCO 3.1.4, "CONTROL ROD Group Alignment Limits," LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT," are entered. Conservative THERMAL POWER reductions are required if the limits on F_Q and $F^N_{\Delta H}$ are exceeded. Verification that F_Q and $F^N_{\Delta H}$ are within limits is also required during MODE 1 PHYSICS TESTS per LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 1."

Measurement uncertainties are applied when F_Q and $F^N_{\Delta H}$ are determined using the Incore Detector System. The measurement uncertainties applied to the measured values of F_Q and $F^N_{\Delta H}$ account for uncertainties in observability and instrument string signal processing.

APPLICABILITY

In MODE 1 with THERMAL POWER greater than 20% RTP, the limits on F_Q and $F^N_{\Delta H}$ must be maintained in order to prevent the core power distribution from exceeding the limits assumed in the analyses of the LOCA and loss of flow accidents. In MODE 1 with THERMAL POWER less than or equal to 20% RTP and in MODES 2, 3, 4, 5, and 6, this LCO is not applicable because the reactor has insufficient stored energy in the fuel or energy being transferred to the coolant to require a limit on the distribution of core power.

The minimum THERMAL POWER level of 20% RTP was chosen based on the ability of the Incore Detector System to satisfactorily obtain meaningful power distribution data.

ACTIONS

The operator must take care in interpreting the relationship of the power peaking factors F_Q and $F^N_{\Delta H}$ to their limits. Limit values of F_Q and $F^N_{\Delta H}$ in the COLR may be expressed in either LHR or in peaking units. Because F_Q and $F^N_{\Delta H}$ are power peaking factors, constant LHR is maintained as THERMAL POWER is reduced, thereby allowing power peaking to be increased in inverse proportion to THERMAL POWER. Therefore, the F_Q and $F^N_{\Delta H}$ limits increase as THERMAL POWER decreases (assuming F_Q and $F^N_{\Delta H}$ are expressed in peaking units) so that a constant LHR limit is maintained.

BASES

ACTIONS (continued)

A.1

When F_Q is determined not to be within its specified limit as determined by a three dimensional power distribution map, a THERMAL POWER reduction is taken to reduce the maximum LHR in the core. Design calculations have verified that a conservative THERMAL POWER reduction is 1% RTP or more for each 1% by which F_Q exceeds its limit. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

Power operation is allowed to continue by Required Action A.1 if THERMAL POWER is reduced by 1% RTP or more from the ALLOWABLE THERMAL POWER for each 1% by which F_Q exceeds its limit. The same reduction in High Flux trip setpoint and Flux-ΔFlux-Flow trip setpoint is required for each 1% by which F_Q is in excess of its limit. These reductions maintain both core protection and OPERABILITY margin at the reduced THERMAL POWER. The required Completion Time of 10 hours is reasonable based on the low probability of an accident occurring in this short time period and the number of steps required to complete the Required Action.

A.3

Continued operation with F_Q exceeding its limit is not permitted, because the initial conditions assumed in the accident analyses are no longer valid. The required Completion Time of 24 hours to restore F_Q within its limits at the reduced THERMAL POWER level is reasonable based on the low probability of a limiting event occurring simultaneously with F_Q exceeding its limit. In addition, it precludes long term depletion with local LHRs higher than the limiting values, and limits the potential for inducing an adverse perturbation in the axial xenon distribution.

BASES

ACTIONS (continued)

B.1

When $F^N_{\Delta H}$ is determined not to be within its acceptable limit as determined by a three dimensional power distribution map, a THERMAL POWER reduction is taken to reduce the maximum LHR in the core. The parameter RH by which THERMAL POWER is decreased per 1% increase in $F^N_{\Delta H}$ above the limit has been verified to be conservative by design calculations, and is defined in the COLR. The parameter RH is the inverse of the increase in $F^N_{\Delta H}$ allowed as THERMAL POWER decreases by 1% RTP, and is based on an analysis of the DNBR during the limiting loss of forced reactor coolant flow transient from various initial THERMAL POWER levels. The required Completion Time of 15 minutes is reasonable for the operator to take the actions necessary to reduce the unit power.

B.2

When a decrease in THERMAL POWER is required because $F^N_{\Delta H}$ has exceeded its limit, Required Action B.2 requires reduction of the High Flux trip setpoint and Flux-ΔFlux-Flow trip setpoint. The amount of reduction of these trip setpoints is governed by the same factor (RH(%) for each 1% that $F^N_{\Delta H}$ exceeds its limit) that determines the THERMAL POWER reduction. This process maintains core protection by providing margin to the trip setpoints at the reduced THERMAL POWER similar to that at RTP. The parameter RH is specified in the COLR. The required Completion Time of 10 hours is reasonable based on the low probability of an accident occurring in this short time period and the number of steps required to complete this Action.

B.3

Continued operation with $F^N_{\Delta H}$ exceeding its limit is not permitted, because the initial conditions assumed in the accident analyses are no longer valid. The required Completion Time of 24 hours to restore $F^N_{\Delta H}$ within its limit at the reduced THERMAL POWER level is reasonable based on the low probability of a limiting event occurring simultaneously with $F^N_{\Delta H}$ exceeding its limit. In addition, this Completion Time precludes long term depletion with an unacceptably high local power and limits the potential for inducing an adverse perturbation in the radial xenon distribution.

BASES

ACTIONS (continued)

C.1

If a THERMAL POWER reduction is not sufficient to restore F_Q or $F^N_{\Delta H}$ within its limit (i.e., the Required Actions and associated Completion Times for Condition A or B are not met), then THERMAL POWER operation should be significantly reduced. The reactor is placed in MODE 1 with THERMAL POWER less than or equal to 20% RTP in which this LCO does not apply. The required Completion Time of 2 hours is a reasonable amount of time for the operator to reduce THERMAL POWER in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.5.1

Core monitoring is performed using the Incore Detector System to obtain a three dimensional power distribution map. Maximum values of F_Q and $F^N_{\Delta H}$ obtained from this map may then be compared with the F_Q and limits in the COLR to verify that the limits have not been exceeded. Measurement of the core power peaking factors in this manner may be used to verify that the measured values of F_Q and $F^N_{\Delta H}$ remain within their specified limits when one or more of the limits specified by LCO 3.1.4, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, or LCO 3.2.4 is exceeded, or when LCO 3.1.8 is applicable. If F_Q and $F^N_{\Delta H}$ remain within their limits when one or more of these parameters exceed their limits, operation at THERMAL POWER may continue because the true initial conditions (the power peaking factors) remain within their specified limits.

Because the limits on F_Q and $F^N_{\Delta H}$ are preserved when the parameters specified by LCO 3.1.4, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, and LCO 3.2.4 are within their limits, a Note is provided in the SR to indicate that monitoring of the power peaking factors is required only when complying with the Required Actions of these LCOs and when LCO 3.1.8 is applicable.

Frequencies for monitoring of the power peaking factors are specified in the Action statements of the individual LCOs. These Frequencies are reasonable based on the low probability of a limiting event occurring simultaneously with either F_Q or $F^N_{\Delta H}$ exceeding its limit, and they provide sufficient time for the operator to obtain a power distribution map from the Incore Detector System. Indefinite THERMAL POWER operation in a Required Action of LCO 3.1.4, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, or LCO 3.2.4 is not permitted, in order to limit the potential for exceeding both the power peaking factors assumed in the accident analyses due to operation with unanalyzed core power distributions and spatial xenon

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.5.1 (continued)

distributions beyond their analyzed ranges. The measured values are required to be adjusted to account for manufacturing tolerances and measurement uncertainties before being compared to the acceptance criteria specified in the COLR. These adjustments are included in the COLR.

REFERENCES

1. 10 CFR 50.46.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor trip to protect against violating the core fuel design limits and the Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs). By tripping the reactor, the RPS also assists the Safety Features Actuation System (SFAS) in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as the LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices...so chosen that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The trip setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the trip setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the trip setpoint plays an important role in ensuring that SLs are not exceeded. As such, the trip setpoint meets the definition of an LSSS and could be used to meet the requirement that they be contained in the Technical Specifications.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety

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Function is to ensure that a SL is not exceeded and therefore the LSSS as defined in 10 CFR 50.36 is the same as the OPERABILITY limit for these devices. However, use of the trip setpoint to define OPERABILITY in Technical Specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a Surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by 10 CFR 50.36 which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the trip setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the trip setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the trip setpoint to account for further drift during the next surveillance interval.

Use of the trip setpoint to define "as found" OPERABILITY and its designation as the LSSS under the expected circumstances described above would result in actions required by both 10 CFR 50.36 and Technical Specifications that are clearly not warranted. However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the CHANNEL FUNCTIONAL TEST (CFT). As such, the Allowable Value differs from the trip setpoint by an amount primarily equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a SL is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. If the actual setting of the device is found to

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have exceeded the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

During AOOs, which are those events expected to occur one or more times during the unit's life, the acceptable limits are:

a. The departure from nucleate boiling ratio (DNBR) shall be maintained above the SL value;

b. Fuel centerline melt shall not occur; and

c. The RCS pressure SL of 2750 psig shall not be exceeded.

Maintaining the parameters within the above values ensures that the offsite dose will be within the 10 CFR 20 and 10 CFR 100 criteria during AOOs.

Design Basis Accidents (DBAs) are events that are analyzed even though they are not expected to occur during the unit's life. During all events, the offsite dose shall be maintained within 10 CFR 100 limits. The consequences of a DBA are considered to be acceptable if the analyzed offsite dose is bounded by 10 CFR 100 limits.

RPS Overview

The RPS consists of four separate redundant protection channels that receive inputs of neutron flux, RCS pressure, RCS flow, RCS temperature, Reactor Coolant Pump (RCP) status, and containment pressure.

Figure 7.2-1, UFSAR, Section 7.2 (Ref. 3), shows the arrangement of a typical RPS protection channel. A protection channel is composed of measurement channels and a reactor trip module (RTM). LCO 3.3.1 provides requirements for the individual measurement channels. These channels encompass all equipment and electronics from the point at which the measured parameter is sensed through the bistable relay contacts in the trip string. LCO 3.3.2, "Reactor Protection System (RPS) Manual Reactor Trip," LCO 3.3.3, "Reactor Protection System (RPS) - Reactor Trip Module (RTM)," and LCO 3.3.4, "CONTROL ROD Drive (CRD) Trip Devices," discuss the remaining elements.

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The RPS instrumentation measures critical unit parameters and compares these to predetermined setpoints. If the setpoint is exceeded, a channel trip signal is generated. The generation of any two trip signals in any of the four RPS channels will result in the trip of the reactor.

The Control Rod Drive (CRD) System contains two types of CRD trip devices: four CRD trip breakers and two silicon controlled rectifier (SCR) relay trip channels. The system has two separate paths (or trip systems), with each path having two AC breakers in series. Each path provides independent power to the CRDs. Either path can provide sufficient power to operate the control rods of the entire CRD System. SCRs are utilized in the CRD power supply to energize the CRD mechanism (CRDM) windings. Two separate power paths to the CRDs ensure that a single failure that opens one path will not cause an unwanted reactor trip.

The RPS consists of four independent protection channels, each containing an RTM. The RTM receives signals from its own measurement channels that indicate a protection channel trip is required. The RTM transmits this signal to its own two-out-of-four trip logic and to the two-out-of-four logic of the RTMs in the other three RPS channels. Whenever any two RPS channels transmit channel trip signals, the RTM logic in each channel actuates to remove 120 VAC power from its associated CRD trip breaker.

The reactor is tripped by opening circuit breakers that interrupt the power supply to the CRDs. Four breakers are installed to increase reliability and allow testing of the trip system. A one-out-of-two taken twice logic is used to interrupt power to the rods.

The arrangements and the relationship of instrumentation channels to trip Functions are discussed next to assist in understanding the overall effect of instrumentation channel failure.

<u>Power Range Nuclear Instrumentation</u>

Power Range Nuclear Instrumentation channels provide inputs to the following trip Functions:

1. High Flux

    a. High Flux - High Setpoint;

    b. High Flux - Low Setpoint;

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7. High Flux/Number of Coolant Pumps On; and

8. Flux - ΔFlux - Flow.

The power range instrumentation has four linear level channels, one for each core quadrant. Each channel feeds one RPS protection channel. Each channel originates in a detector assembly containing two uncompensated ion chambers. The ion chambers are positioned to represent the top half and bottom half of the core. The individual currents from the chambers are fed to individual linear amplifiers. The summation of the top and bottom is the total reactor power. The difference of the top minus the bottom neutron signal is the measured AXIAL POWER IMBALANCE of the reactor core.

RC High Temperature

The RC High Temperature provides input to the following Functions:

2. RC High Temperature; and

5. RC Pressure - Temperature.

The RC High Temperature is measured by two resistance elements in each hot leg, for a total of four. One temperature detector is associated with each protection channel.

Reactor Coolant System Pressure

The Reactor Coolant System Pressure provides input to the following Functions:

3. RC High Pressure;

4. RC Low Pressure;

5. RC Pressure - Temperature; and

11. Shutdown Bypass High Pressure.

The RPS inputs of reactor coolant pressure are provided by two pressure transmitters in each hot leg, for a total of four. One sensor is associated with each protection channel.

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Containment Pressure

The Containment Pressure measurements provide input only to the Containment High Pressure trip, Function 6. There are four Containment High Pressure switches, one associated with each protection channel.

Reactor Coolant Pump Monitoring

Reactor coolant pump monitors are inputs to the High Flux/Number of Coolant Pumps On trip, Function 7. Each RCP motor has four RCP monitoring circuits. A current transformer on one phase of each RCP motor provides current signals to four current transducer circuits. Each circuit is able to detect an RCP motor overcurrent condition, as would be found with an overloaded or binding shaft, and an RCP motor undercurrent condition, as would be found with a sheared shaft. Each power monitoring channel circuit provides RCP run status to each of the four RPS channels. A closed contact indicates normal operation and an open contact indicates an abnormal condition.

Reactor Coolant System Flow

The Reactor Coolant System Flow measurements are an input to the Flux - ΔFlux - Flow trip, Function 8. The reactor coolant flow inputs to the RPS are provided by eight high accuracy differential pressure transmitters (flow rate measurement sensors), four on each loop, which measure flow through gentile tubes. One flow input in each loop is associated with each protection channel. The correlation of sensed flow with RCS total flow is ensured during the precision flow rate measurement test required by SR 3.4.1.4.

RPS Bypasses

The RPS is designed with two types of bypasses: channel bypass and shutdown bypass.

Channel bypass provides a method of placing all Functions in one RPS protection channel in a bypassed condition, and shutdown bypass provides a method of leaving the safety rods withdrawn during cooldown and depressurization of the RCS and provides a method to allow control rod drive testing and startup/shutdown testing after the reactor has been shutdown and depressurized below the low pressure trip setpoint. Each bypass is discussed next.

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Channel Bypass

A channel bypass provision is provided to allow for maintenance and testing of the RPS. The use of channel bypass keeps the protection channel trip relay energized regardless of the status of the instrumentation channel bistable relay contacts. The bypass is initiated using a key switch. Placing a channel in channel bypass interlocks the other three channels, preventing a second channel from being bypassed. The other three channels are prevented from being bypassed by the removal of the ground return path to the bypass circuits. When the bypass relay is energized, the bypass contact closes, maintaining the channel trip relay in an energized condition. All RPS trips are reduced to a two-out-of-three logic with a channel in bypass.

Shutdown Bypass

During unit cooldown, it may be desirable to withdraw the safety rods to provide shutdown capabilities in the event of unusual positive reactivity additions (moderator dilution, etc.).

However, the unit is also depressurized as coolant temperature is decreased. If the safety rods are withdrawn and coolant pressure is decreased, an RC Low Pressure trip will occur at 1900 psig and the rods will fall into the core. To avoid this, the protection system allows the operator to bypass the low pressure trip and maintain shutdown capabilities. During the cooldown and depressurization, the safety rods are inserted prior to the low pressure trip of 1900 psig. The RCS pressure is decreased to less than 1820 psig, then each RPS channel is placed in shutdown bypass.

Actuating the Shutdown Bypass switch opens the bistable trip string thereby ensuring the channel is tripped before shutdown bypass mode can be entered. This action bypasses the RC Low Pressure trip, Flux - ΔFlux - Flow trip, High Flux/Number of Reactor Coolant Pumps On trip, and the RC Pressure - Temperature trip, and inserts a shutdown bypass High Pressure, 1820 psig trip. The operator can then withdraw the safety rods for additional trippable reactivity.

The insertion of the shutdown bypass high pressure trip performs two functions. First, with a trip setpoint of 1820 psig, the bistable prevents operation at normal system pressure, 2155 psig, with a portion of the RPS bypassed. The second function is to ensure that the bypass is removed prior to normal operation. When the RCS pressure is increased

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during a unit heatup, the safety rods are inserted prior to reaching 1820 psig. The shutdown bypass is removed, which returns the RPS to normal, and system pressure is increased to greater than 1900 psig. The safety rods are then withdrawn and remain at the full out condition for the rest of the heatup.

In addition to the Shutdown Bypass High Pressure trip, the High Flux trip setpoint is administratively reduced to ≤ 5% RTP while the RPS is in shutdown bypass. This provides a backup to the Shutdown Bypass High Pressure trip and allows low temperature physics testing while preventing the generation of any significant amount of power. Sufficient natural circulation would be available to remove 5% of RTP if none of the RCPs were operating.

Interlocks

Electro-mechanical interlocks initiate an RPS channel trip whenever: (1) a test module that is used to test one of the seven trip bistables or the containment pressure switch contact buffer is placed in the test mode; or (2) any module vital to a trip signal is withdrawn, unless the RPS channel is bypassed. Removal of the RTM in any condition will trip its associated CRD breaker. Another interlock is used to prevent the bypassing of more than one channel. Once a bypass is initiated, the other three channels are prevented from being bypassed by the removal of the ground return path to the bypass circuits.

Trip Setpoints/Allowable Value

The trip setpoints are the normal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.

The trip setpoints used in the bistables are based on the analytical limits stated in UFSAR, Table 15.1-2, UFSAR Section 15.1.2 (Ref. 4). The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing uncertainties are taken into account. To allow for calibration tolerances, instrumentation uncertainties, and instrument drift that are not present or are not measured during CHANNEL FUNCTIONAL TESTS, and severe environment errors for those RPS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values specified in Table 3.3.1-1 are conservatively adjusted with respect to the analytical limits. The trip setpoint is established using Method 1 or Method 2 of Reference 6 or 7.

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The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION. One example of such a change in measurement error is drift during the Surveillance Frequency. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Setpoints in accordance with the Allowable Value ensure that the limits of Chapter 2.0, "Safety Limits," in the Technical Specifications are not violated during AOOs and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed. Note that in LCO 3.3.1 the Allowable Values listed in Table 3.3.1-1 are the LSSS.

Each channel can be tested online to verify that the signal and setpoint accuracy are within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. Surveillances for the channels are specified in the SR section.

The Allowable Values listed in Table 3.3.1-1 are established using Method 1 or Method 2 of Reference 6 or 7, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of those uncertainties are factored into the determination of each trip setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in Reference 8 takes credit for most RPS trip Functions. Functions not specifically credited in the accident analysis are Containment High Pressure, RC high temperature, High Flux - Low Setpoint, and Shutdown Bypass High Pressure.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions. The four channels of each Function in Table 3.3.1-1 of the RPS instrumentation shall be OPERABLE during its specified Applicability to ensure that a reactor trip will be actuated if needed. Additionally, during shutdown bypass with any CRD trip breaker closed and the CRD System capable of rod withdrawal, the applicable RPS Functions must also be available. This ensures the capability to trip the withdrawn CONTROL RODS exists at all times that rod motion is possible. The trip Function channels specified in Table 3.3.1-1 are considered OPERABLE when all channel components necessary to provide a reactor trip are functional and in service for the required MODE or Other Specified Condition listed in Table 3.3.1-1.

Only the Allowable Values are specified for each RPS trip Function in the LCO. Nominal trip setpoints are specified in the unit specific setpoint calculations except for Functions 1.a and 5. For these two Functions, the Limiting Trip Setpoint and methodology used to determine the Limiting Trip Setpoint, the predefined as-found acceptance criteria, and the as-left tolerance are specified in the TRM (Ref. 2). In no case shall the predefined as-found acceptance criteria band overlap the Allowable Value. If one end of the predefined as-found acceptance criteria band is truncated due to its proximity to the Allowable Value, this does not affect the other end of the predefined as-found acceptance criteria band. If equipment is replaced, such that the previous as-left value is not applicable to the current configuration, the as-found acceptance criteria band is not applicable to calibration activities performed immediately following the equipment replacement. The nominal setpoints are selected to ensure that the setpoint measured by CHANNEL FUNCTIONAL TESTS and CHANNEL CALIBRATION does not exceed the Allowable Value if the bistable is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable provided that operation and testing are consistent with the assumptions of the unit specific setpoint calculations. Each Allowable Value specified is more conservative than instrument uncertainties appropriate to the trip Function. These uncertainties are defined in Reference 6 or 7.

For most RPS Functions, the Allowable Value is to ensure that the departure from nucleate boiling (DNB) or RCS pressure SLs are not challenged. Cycle specific figures for use during operation are contained in the COLR.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In addition, the LCO also requires the ultrasonic flow meter (UFM) instrumentation to be used to perform SR 3.3.1.2 when THERMAL POWER is > 50% RTP. The use of the UFM instrumentation for the secondary side feedwater flow and feedwater temperature inputs into the heat balance calculation provides an uncertainty of 0.37% above 50% RTP. An uncertainty of 2% is assumed when non-UFM instrumentation is used for the secondary-side feedwater flow and feedwater temperature inputs into the heat balance calculation. At ≤ 50% RTP, the heat balance is performed using primary side instrumentation. Hence, this part of the LCO is only applicable above 50% RTP.

The UFM includes a flow meter measurement section in each of the two main feedwater flow headers. Each measurement section consists of sixteen ultrasonic transducers. With any transducer inoperable, the UFM instrumentation cannot be used to perform SR 3.3.1.2.

Certain RPS trips function to indirectly protect the SLs by detecting specific conditions that do not immediately challenge SLs but will eventually lead to challenge if no action is taken. These trips function to minimize the unit transients caused by the specific conditions. The Allowable Value for these Functions is selected at the minimum deviation from normal values that will indicate the condition, without risking spurious trips due to normal fluctuations in the measured parameter.

The safety analyses applicable to each RPS Function are discussed next.

1. High Flux

   a. High Flux - High Setpoint

      The High Flux - High Setpoint trip provides protection for the design thermal overpower condition based on the measured out of core fast neutron leakage flux.

      The High Flux - High Setpoint trip initiates a reactor trip when the neutron power reaches a predefined setpoint at the design overpower limit. Because THERMAL POWER lags the neutron power, tripping when the neutron power reaches the design overpower will limit THERMAL POWER to a maximum value of the design overpower. Thus, the High Flux - High Setpoint trip protects against violation of the DNBR and fuel centerline melt SLs.

      The High Flux - High Setpoint trip provides transient protection for rapid positive reactivity excursions during operations. These events include the uncontrolled control rod assembly group

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

withdrawal from a subcritical condition event, uncontrolled rod assembly group withdrawal at power event, the rod ejection accident, and the steam line break accident. By providing a trip during these events, the High Flux - High Setpoint trip protects the unit from excessive power levels and also serves to reduce reactor power to prevent violation of the RCS pressure SL.

Rod withdrawal accident analyses cover a large spectrum of reactivity insertion rates (rod worths), which exhibit slow and rapid rates of power increases. At high reactivity insertion rates, the High Flux - High Setpoint trip provides the primary protection. At low reactivity insertion rates, the high pressure trip provides primary protection.

The specified Allowable Values are selected to provide protection against DNB and fuel centerline melt. Allowable Values are provided for four reactor coolant pump operation and three reactor coolant pump operation. The three reactor coolant pump operation Allowable Value is only applicable when reset in accordance with LCO 3.4.4, "RCS Loops - MODES 1 and 2." In addition, ITS Table 3.3-1 Footnote (e) provides a lower four reactor coolant pump operation Allowable Value that is applicable only when reset in accordance with ACTION F. This is required when the UFM is not used during performance of SR 3.3.1.2. The normal RPS High Flux - High Setpoint Allowable Value is based on the assumption that the required high accuracy secondary heat balance instrumentation (i.e., the UFM) is necessary to provide sufficient margin to the analytical setpoint. When the UFM is not used to perform SR 3.3.1.2, the Allowable Value is reduced to account for the difference in heat balance error between the UFM instrumentation and non-UFM instrumentation. No reduction in the three reactor coolant pump operation Allowable Value is needed since the normal Allowable Value is conservative and bounds operation irrespective of the use of the UFM for heat balance calculation. The Allowable Values do not account for harsh environment induced errors, because the trip will actuate prior to degraded environmental conditions being reached.

b. <u>High Flux - Low Setpoint</u>

While in shutdown bypass, with the Shutdown Bypass High Pressure trip OPERABLE, the High Flux - Low Setpoint trip must be reduced to ≤ 5% RTP. The low power setpoint, in conjunction with the lower Shutdown Bypass High Pressure setpoint, ensure

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

that the unit is protected from excessive power conditions when other RPS trips are bypassed.

The setpoint Allowable Value was chosen to be as low as practical and still lie within the range of the out of core instrumentation.

2. RC High Temperature

The RC High Temperature trip, in conjunction with the RC Low Pressure and RC Pressure - Temperature trips, provides protection for the DNBR SL. A trip is initiated whenever the reactor vessel outlet temperature approaches the conditions necessary for DNB. Portions of each RC High Temperature trip channel are common with the RC Pressure - Temperature trip. The RC High Temperature trip provides steady state protection for the DNBR SL. The RC High Temperature trip provides backup protection for RCS overheating events such as loss of normal feedwater and is credited in the makeup and purification system malfunction event.

The RC High Temperature trip limits the maximum RCS temperature to below the highest value for which DNB protection by the RC Pressure - Temperature trip is ensured. The Allowable Value is selected to ensure that a trip occurs before hot leg temperatures reach the point beyond which the RC Low Pressure and RC Pressure - Temperature trips are analyzed. Above the high temperature trip, the RC Pressure - Temperature trip need not provide protection, because the unit would have tripped already. The Allowable Value does not reflect errors induced by harsh environmental conditions that the equipment is expected to experience because the trip is not required to mitigate accidents that create harsh conditions in the containment.

3. RC High Pressure

The RC High Pressure trip works in conjunction with the pressurizer code safety valves to prevent RCS overpressurization, thereby protecting the RCS Pressure SL.

The RC High Pressure trip has been credited in the accident analysis calculations for slow positive reactivity insertion transients uncontrolled control rod assembly group withdrawal from a subcritical condition, uncontrolled rod assembly group withdrawal at power, makeup and purification system malfunction, loss of normal feedwater transients and control rod assembly ejection accident. The uncontrolled control rod assembly group withdrawal events cover a

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

large spectrum of reactivity insertion rates and rod worths that exhibit slow and rapid rates of power increases. At high reactivity insertion rates, the High Flux - High Setpoint trip provides the primary protection. At low reactivity insertion rates, the RC High Pressure trip provides the primary protection.

The Allowable Value is selected to ensure that the RCS Pressure SL is not challenged during steady state operation or slow power increasing transients. The Allowable Value does not reflect errors induced by harsh environmental conditions because the equipment is not required to mitigate accidents that create harsh conditions in the containment.

4. RC Low Pressure

The RC Low Pressure trip, in conjunction with the RC High Temperature and RC Pressure - Temperature trips, provides protection for the DNBR SL. A trip is initiated whenever the system pressure approaches the conditions necessary for DNB. The RC Low Pressure trip provides DNB low pressure limit for the RC Pressure - Temperature trip.

The RC Low Pressure Allowable Value is selected to ensure that a reactor trip occurs before RCS pressure is reduced below the lowest point at which the RC Pressure - Temperature trip is analyzed. The RC Low Pressure trip provides protection for primary system depressurization events and has been credited in the accident analysis calculations for steam generator tube rupture, steam line break, and small break loss of coolant accidents (LOCAs). The Allowable Value does not reflect errors induced by harsh environmental conditions because the containment environment is not extensively degraded before the trip occurs.

5. RC Pressure - Temperature

The RC Pressure - Temperature trip, in conjunction with the RC High Temperature and RC Low Pressure trips, provides protection for the DNBR SL during steady state condition. A trip is initiated whenever the system parameters of pressure and temperature approach the conditions necessary for DNB. The RC Pressure - Temperature trip provides a floating low pressure trip based on the RC High Temperature within the range specified by the RC High Temperature and RC Low Pressure trips.

The RC Pressure - Temperature Allowable Value is selected to ensure that a trip occurs when temperature and pressure approach

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the conditions necessary for DNB while operating in a temperature pressure region constrained by the low pressure and high temperature trips. The RC Pressure - Temperature trip is not assumed for transient protection in the safety analysis; therefore, determination of the Allowable Value does not account for errors induced by a harsh Containment environment.

6. Containment High Pressure

The Containment High Pressure trip provides an early indication of a high energy line break (HELB) inside the containment. By detecting changes in the containment pressure, the RPS can provide a reactor trip before the other system parameters have varied significantly. Thus, this trip acts to minimize accident consequences. It also provides a backup for RPS trip instruments exposed to a containment HELB environment.

The Allowable Value for Containment High Pressure trip is set at the lowest value consistent with avoiding spurious trips during normal operation. This Containment High Pressure trip is not credited in the safety analyses, however it can trip the plant during small, high energy line breaks inside containment, such as LOCAs, steam line breaks, and feedwater line breaks. The components of the Containment High Pressure trip are located in an area that is not exposed to high temperature steam environments during HELB transients.

7. High Flux/Number of Coolant Pumps On

The High Flux/Number Coolant Pumps On trip provides protection for changes in the reactor coolant flow due to the loss of multiple reactor coolant pumps (RCPs). Because the flow reduction lags loss of power indications due to the inertia of the RCPs, the trip initiates protective action earlier than a trip based on a measured flow signal.

The trip also prevents operation with both pumps in either coolant loop tripped. Under these conditions, core flow and core fluid mixing are insufficient for adequate heat transfer. Thus, the High Flux/Number of Coolant Pumps On trip functions to protect the DNBR and fuel centerline melt SLs.

The High Flux/Number of Coolant Pumps On trip has been credited in the accident analysis calculations for the loss of four RCPs. The trip also provides the primary protection for the loss of a pump or pumps, which would result from both pumps in a single steam generator loop being tripped.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Allowable Values for the High Flux/Number of Coolant Pumps On trip are selected to prevent normal (100%) power operation unless at least three RCPs are operating. RCP status is monitored by current transducers on each pump. The transducer channel indicates a loss of an RCP on overcurrent and on undercurrent. During a RCP motor overcurrent condition, as would be found with an overloaded or binding shaft, one set of output contacts will open. During a RCP motor undercurrent condition, as would be found with a sheared shaft, a second set of output contacts will open. Neither the reactor power Allowable Values nor the current transducer setpoint account for instrumentation errors caused by harsh environments because the trip Function is not required to respond to events that could create harsh environments around the equipment.

8. Flux - ΔFlux - Flow

The Flux - ΔFlux - Flow trip provides steady state protection for the DNB and fuel centerline melt temperature SLs. A reactor trip is initiated when the core power, AXIAL POWER IMBALANCE, and reactor coolant flow conditions indicate an approach to DNB or fuel centerline melt limits.

This trip supplements the protection provided by the High Flux/Number of Coolant Pumps On trip, through the power to flow ratio, for loss of reactor coolant flow events. The power to flow ratio provides direct protection for the DNB and fuel centerline melt temperature SLs for the loss of a single RCP and for locked RCP rotor accidents. The imbalance portion of the trip is credited for steady state protection only.

The power to flow ratio of the Flux - ΔFlux - Flow trip also provides steady state protection to prevent reactor power from exceeding the allowable power when the primary system flow rate is less than full four pump flow. Thus, the power to flow ratio prevents overpower conditions similar to the High Flux - High Setpoint trip. This protection ensures that during reduced flow conditions the core power is maintained below that required to begin DNB.

The Allowable Value is selected to ensure that a trip occurs when the core power, axial power peaking, and reactor coolant flow conditions indicate an approach to DNB or fuel centerline melt limits. By measuring reactor coolant flow and by tripping only when conditions approach an SL, the unit can operate with the loss of one pump from a four pump initial condition. The Allowable Value for this Function is given in the unit COLR because the cycle specific core peaking changes affect the Allowable Value.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Shutdown Bypass High Pressure

The RPS shutdown bypass is provided to allow for withdrawing the CONTROL RODS prior to reaching the normal RC Low Pressure trip setpoint. The Shutdown Bypass High Pressure trip provides protection during deboration and RCS heatup by allowing the operator to withdraw the safety groups of CONTROL RODS. This makes their negative reactivity available to terminate inadvertent reactivity excursions. Use of the shutdown bypass trip requires that the High Flux - High Setpoint Allowable Value be reduced to 5% of full power or less. The Shutdown Bypass High Pressure trip forces a reactor trip to occur whenever the unit switches from power operation to shutdown bypass or vice versa. This ensures that the CONTROL RODS are all inserted and the flux distribution is known before power operation can begin. The operator is required to remove the shutdown bypass, reset the High Flux - High Setpoint trip, and again withdraw the safety rod groups before proceeding with startup.

Accidents analyzed in the UFSAR, Section 15.0 (Ref. 8), do not describe events that occur during shutdown bypass operation, because the consequences of these events are enveloped by the events presented in the UFSAR.

During shutdown bypass operation with the Shutdown Bypass High Pressure trip active with a setpoint of ≤ 1820 psig and the High Flux - Low Setpoint set at or below 5% RTP, the (numbered) trip Functions listed below are bypassed. Under these conditions, the Shutdown Bypass High Pressure trip and the High Flux - Low Setpoint trip act to prevent unit conditions from reaching a point where actuation of these trip Functions is necessary:

4. RC Low Pressure;

5. RC Pressure - Temperature;

7. High Flux/Number of Coolant Pumps On; and

8. Flux - ΔFlux - Flow.

The Shutdown Bypass High Pressure Function's Allowable Value is selected to ensure a trip occurs before producing THERMAL POWER.

The RPS Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODES 1 and 2, the following (numbered) trip Functions shall be OPERABLE because the reactor is critical in these MODES. These trips are designed to take the reactor subcritical to maintain the SLs during AOOs and to assist the SFAS in providing acceptable consequences during accidents.

1.a High Flux - High Setpoint;

2. RC High Temperature;

3. RC High Pressure;

4. RC Low Pressure;

5. RC Pressure - Temperature;

6. Containment High Pressure;

7. High Flux/Number of Coolant Pumps On; and

8. Flux - ΔFlux - Flow.

Functions 4, 5, 7, and 8 are bypassed in MODE 2 when RCS pressure is below 1820 psig, provided the Shutdown Bypass High Pressure and the High Flux - Low Setpoint trip are placed in operation. Under these conditions, the Shutdown Bypass High Pressure trip and the High Flux - Low Setpoint trip act to prevent unit conditions from reaching a point where actuation of these Functions is necessary.

In MODE 3 when not operating in shutdown bypass but with any CRD trip breaker in the closed position and the CRD System capable of rod withdrawal, the High Flux - High Setpoint trip and the RC High Pressure trip are required to be OPERABLE.

Because the only safety function of the RPS is to trip the CONTROL RODS, the RPS is not required to be OPERABLE in MODE 3, 4, or 5 if the reactor trip breakers are open, or the CRD System is incapable of rod withdrawal. Similarly, the RPS is not required to be OPERABLE in MODE 6 when the CONTROL RODS are decoupled from the CRDs.

However, in MODE 2, 3, 4, or 5, the Shutdown Bypass High Pressure and High Flux - Low Setpoint trips are required to be OPERABLE if the CRD trip breakers are closed and the CRD System is capable of rod withdrawal. Under these conditions, the Shutdown Bypass High Pressure and High Flux - Low Setpoint trips are sufficient to prevent an approach to conditions that could challenge SLs.

ACTIONS

Conditions A, B, and C are applicable to all RPS protection Functions. If a channel's trip setpoint is found non-conservative with respect to the required Allowable Value in Table 3.3.1-1, or the transmitter, instrument loop, signal processing electronics or bistable is found inoperable, the channel must be declared inoperable and the applicable Condition must be entered immediately.

A.1

If one or more Functions in one protection channel become inoperable, the affected protection channel must be placed in bypass or trip. If the channel is bypassed, all RPS Functions are placed in a two-out-of-three logic configuration and the bypass of any other channel is prevented. In this configuration, the RPS can still perform its safety function in the presence of a random failure of any single channel. Alternatively, the inoperable channel can be placed in trip. Tripping the affected protection channel places all RPS Functions in a one-out-of-three configuration.

Operation in the two-out-of-three configuration or in the one-out-of-three configuration may continue indefinitely based on the NRC SER for BAW-10167, Supplement 2 (Ref. 9). In this configuration, the RPS is capable of performing its trip Function in the presence of any single random failure. The 1 hour Completion Time is sufficient to perform Required Action A.1.

B.1 and B.2

For Required Action B.1 and Required Action B.2, if one or more Functions in two protection channels become inoperable, one of two inoperable protection channels must be placed in trip and the other in bypass. These Required Actions place all RPS Functions in a one-out-of-two logic configuration and prevent bypass of a second channel. In this configuration, the RPS can still perform its safety functions in the presence of a random failure of any single channel. The 1 hour Completion Time is sufficient time to perform Required Action B.1 and Required Action B.2.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.1-1. The applicable Condition referenced in the table is Function dependent. If the Required Action and the associated Completion Time of Condition A or B are not met or if more than two channels are inoperable, Condition C is entered to provide for transfer to the appropriate subsequent Condition.

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Action and associated Completion Time of Condition A or B are not met or if more than two channels are inoperable, and Table 3.3.1-1 directs entry into Condition D, the unit must be brought to a MODE in which the specified RPS trip Functions are not required to be OPERABLE. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and to open all CRD trip breakers without challenging plant systems. As Noted, the CRD trip breakers are only required to be opened for Functions 1.a, 3, and 6.

E.1

If the Required Action and associated Completion Time of Condition A or B are not met or if more than two channels are inoperable, and Table 3.3.1-1 directs entry into Condition E, the unit must be brought to a condition in which the specified RPS trip Functions are not required to be OPERABLE. To achieve this status, all CRD trip breakers must be opened. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to open CRD trip breakers without challenging plant systems.

F.1, F.2, and F.3

If the UFM is not available for use, the heat balance can be performed using inputs from less accurate installed instrumentation. However, since these instruments are not as accurate, action must be immediately initiated to reduce THERMAL POWER to $\leq$ 98.4% RTP with four reactor coolant pumps operating (Required Action F.1) and $\leq$ 73.8% RTP with three reactor coolant pumps operating (Required Action F.2). Given the larger heat balance uncertainty, these limits preserve the core power used in the accident analysis and the initial conditions for DNB as required by LCO 3.2.1, "Regulating Rod Insertion Limits." Actions to reduce power, once initiated, must continue until power is reduced to within the required limit. The immediate Completion Time reflects the importance of reducing power since the heat balance uncertainty when not using the UFM is larger than assumed.

In addition, when operating with four reactor coolant pumps, the Reactor Protection System High Flux – High Setpoint Allowable Value must be reset to the value specified in Table 3.3.1-1 Note (e) within ten hours (Required Action F.3). This reduction ensures that when the increased uncertainty of the instrumentation is considered, the maximum analytical

BASES

ACTIONS

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

setpoint value of 110.2% RTP will not be exceeded as required by the safety analyses. Historical comparison of the two feedwater flow measurement systems used for secondary-side heat balance calculations above 50% RTP, UFM-based and feedwater venturi-based, indicates that the two methods do not diverge significantly during power operations over short periods of time. The long-term fouling of the venturis results in a more conservative feedwater flow input to the heat balance calculation. Nuclear Instrumentation (NI) trend analysis indicates that the NI to heat balance comparison will not drift significantly over a three-week period, and surveillance data indicates essentially no drift of the RPS High Flux - High Setpoint trip setpoints. Accordingly, the accuracy and conservatism of the RPS High Flux –High Setpoint trip is acceptable in the ten hour period provided for Allowable Value reduction after completion of the non-UFM-based heat balance calculation.

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function. Most Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, CHANNEL CALIBRATION, and RPS RESPONSE TIME testing.

The SRs are modified by a Note. The Note directs the reader to Table 3.3.1-1 to determine the correct SRs to perform for each RPS Function.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the transmitter or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal but more frequent checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels.

For Functions that trip on a combination of several measurements, such as the Flux - ΔFlux - Flow, the CHANNEL CHECK must be performed on each input.

SR 3.3.1.2

This SR is the performance of a heat balance calibration for the power range channels every 24 hours when reactor power is ≥ 15% RTP. The heat balance calibration consists of a comparison of the results of the calorimetric with the power range channel output. The outputs of the power range channels are normalized to the calorimetric. Note 1 to the SR clarifies that if the calorimetric heat balance calculation results exceed the Nuclear Instrumentation System (NIS) channel output by > 2% RTP, the NIS is not declared inoperable but must be adjusted. If the NIS channel cannot be properly adjusted, the channel is declared inoperable. Note 2 clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The power range channel's output shall be adjusted consistent with the calorimetric results if the calorimetric heat balance calculation results exceed the power range channel's output by > 2% RTP. The value of 2% is adequate because this value is assumed in the safety analyses of UFSAR, Chapter 15 (Ref. 8). These checks and, if necessary, the adjustment of the power range channels ensure that channel accuracy is maintained within the analyzed error margins. The 24 hour Frequency is adequate, based on unit operating experience, which demonstrates the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

change in the difference between the power range indication and the calorimetric results rarely exceeds a small fraction of 2% RTP in any 24 hour period. Furthermore, the control room operators monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the unit specific setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint analysis. The Surveillance includes two Notes. The first Note to the Surveillance indicates that neutron detectors are excluded from CHANNEL CALIBRATION. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. The second Note states that for Function 8, Flux - ΔFlux - Flow, flow rate measurement sensors may be excluded from CHANNEL CALIBRATION for this SR. This is acceptable because these sensors are calibrated in accordance with SR 3.3.1.7 every 24 months.

The Frequency is justified by the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. However, the test is performed every 23 days on a STAGGERED TEST BASIS.

SR 3.3.1.3 for Function 1.a is modified by two Notes as identified in Table 3.3.1-1. Function 1.a is an LSSS for protection system instrument channels that protect reactor core or RCS pressure boundary Safety Limits. Some components (e.g., mechanical devices which have an on or off output or an open/close position such as limit switches, float switches, and proximity detectors) are not calibrated in the traditional sense and do not have as-left or as-found conditions that would indicate drift of the component setpoint. These devices are considered not trendable and the requirements of the Notes are not required to be applied to the mechanical portion of the functions. Where a non-trendable component provides signal input to other channel components

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

that can be trended, the remaining components must be evaluated in accordance with the Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. For digital channel components, the as-found tolerance may be identical to the as-left tolerance since drift may not be an expected error. In these cases a channel as-found value outside the as-left condition may be cause for component assessment. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance around the Limiting Trip Setpoint (LTSP), or a value that is more conservative than the LTSP. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance or a setting more conservative than the LTSP, then the instrument channel shall be declared inoperable. The second Note also requires that the LTSP and the methodology used to determine the LTSP, the predefined as-found acceptance band, and the as-left setpoint tolerance band are specified in the Technical Requirements Manual (TRM) (Ref. 2).

SR 3.3.1.4

A comparison of power range nuclear instrumentation channels against incore detectors shall be performed at a 31 day Frequency when reactor power is ≥ 50% RTP and THERMAL POWER is steady. The SR is modified by two Notes. Note 2 clarifies that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP. Note 1 clarifies that if the absolute difference between the power range and incore measurements is ≥ 2.5%, the power range channel is not inoperable, but an adjustment of the measured imbalance to agree with the incore measurements is necessary. If the power range channel cannot be properly recalibrated, the channel is declared inoperable. The calculation of the Allowable Value envelope assumes a difference in out of core to incore measurements of 2.5%. Additional inaccuracies beyond those that are measured are also included in the setpoint envelope calculation. The

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

31 day Frequency is adequate, considering that long term drift of the excore linear amplifiers is small and burnup of the detectors is slow. Also, the excore readings are a strong function of the power produced in the peripheral fuel bundles, and do not represent an integrated reading across the core. The slow changes in neutron flux during the fuel cycle can also be detected at this interval.

SR 3.3.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required RPS channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Setpoints must be found within the Allowable Values specified in Table 3.3.1-1. Any setpoint adjustment shall be consistent with the assumptions of the current unit specific setpoint analysis.

The as-found and as-left values were recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 9).

The Frequency of 46 days on a STAGGERED TEST BASIS is consistent with the calculations of Reference 10 that indicate the RPS retains a high level of reliability for this test interval.

SR 3.3.1.5 for Function 5 is modified by two Notes as identified in Table 3.3.1-1. Function 5 is an LSSS for protection system instrument channels that protect reactor core or RCS pressure boundary Safety Limits. Some components (e.g., mechanical devices which have an on or off output or an open/close position such as limit switches, float switches, and proximity detectors) are not calibrated in the traditional sense and do not have as-left or as-found conditions that would indicate drift of the component setpoint. These devices are considered not trendable and the requirements of the Notes are not required to be applied to the mechanical portion of the functions. Where a non-trendable component provides signal input to other channel components that can be trended, the remaining components must be evaluated in accordance with the Notes. The first Note requires evaluation of channel performance for the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.5 (continued)

condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. For digital channel components, the as-found tolerance may be identical to the as-left tolerance since drift may not be an expected error. In these cases a channel as-found value outside the as-left condition may be cause for component assessment. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance around the Limiting Trip Setpoint, or a value that is more conservative than the Limiting Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance or a setting more conservative than the LTSP, then the instrument channel shall be declared inoperable. The second Note also requires that the LTSP and the methodology used to determine the LTSP, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in the TRM (Ref. 2).

SR 3.3.1.6

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the unit specific setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint analysis.

The Frequency is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.7

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the unit specific LTSP analysis. CHANNEL CALIBRATONS must be performed consistent with the assumptions of the unit specific setpoint analysis. Whenever a resistance temperature detector (RTD) sensing element is replaced, the next required CHANNEL CALIBRATION of the RTD sensors is accomplished by an inplace qualitative calibration that compares the other sensing elements with the recently installed sensing element. A Note to the SR states that for Function 8, Flux - ΔFlux - Flow, only the flow rate measurement sensors are required to be calibrated.

The Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.7 for Function 5 is modified by two Notes as identified in Table 3.3.1-1. Function 5 is an LSSS for protection system instrument channels that protect reactor core or RCS pressure boundary Safety Limits. Some components (e.g., mechanical devices which have an on or off output or an open/close position such as limit switches, float switches, and proximity detectors) are not calibrated in the traditional sense and do not have as-left or as-found conditions that would indicate drift of the component setpoint. These devices are considered not trendable and the requirements of the Notes are not required to be applied to the mechanical portion of the functions. Where a non-trendable component provides signal input to other channel components that can be trended, the remaining components must be evaluated in accordance with the Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. For digital channel components, the as-found tolerance may be identical to the as-left tolerance since drift may not be an expected error. In these cases a channel as-found value outside the as-left condition may be cause for component assessment. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance around the LTSP, or a value that is more conservative than the LTSP. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance or a setting more conservative than the LTSP, then the instrument channel shall be declared inoperable. The second Note also requires that the LTSP and the methodology used to determine the LTSP, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in the TRM (Ref. 2).

SR 3.3.1.8

This SR verifies individual channel actuation response times are less than or equal to the maximum values assumed in the accident analysis. Individual component response times are not modeled in the analyses. The analyses model the overall, or total, elapsed time from the point at which the parameter exceeds the analytical limit at the sensor to the point of rod insertion (CRD trip breakers open). Thus, this SR encompasses the reactor trip module components covered by LCO 3.3.3 and the operation of the mechanical components covered by LCO 3.3.4 (i.e., the CRD trip breakers). Response time testing acceptance criteria are included in Reference 2.

A Note to the Surveillance indicates that neutron detectors are excluded from RPS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. The response time of the neutron flux signal portion of the channel shall be measured from the neutron detector output or from the input of the first electronic components in the channel.

Response time tests are conducted on a 24 month STAGGERED TEST BASIS. Testing of the final actuation device (the CRD breakers) is included in the testing of each channel. Therefore, staggered testing results in response time verification of these devices every 96 months. The 24 month Frequency is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

BASES

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety Related Instrumentation."

2. Technical Requirements Manual.

3. Figure 7.2-1, UFSAR 7.2.

4. Table 15.1-2, UFSAR Section 15.1.2.

5. 10 CFR 50.49.

6. ISA 67.04-Part II-1994, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."

7. ISA 67.04.02-2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."

8. UFSAR, Section 15.0.

9. NRC SER for Amendment No. 185 to Facility Operating License No. NPF-3, Davis-Besse, dated March 28, 1994.

10. BAW-10167, May 1986.

B 3.3 INSTRUMENTATION

B 3.3.2 Reactor Protection System (RPS) Manual Reactor Trip

BASES

BACKGROUND	The RPS Manual Reactor Trip provides the operator with the capability to trip the reactor from the control room in the absence of any other trip condition. Manual trip is provided by two trip push buttons located in the control room and mounted on either side of the rod control panel. Each push button operates eight electrically independent switch contacts, one for each side of the undervoltage coil for each breaker. This trip is independent of the automatic trip system. Power for the CONTROL ROD drive (CRD) breaker undervoltage coils and contactor coils comes from the reactor trip modules (RTMs). Opening of the switch contacts opens the lines to the breakers, tripping them. The switch contacts also energize the breaker shunt trip mechanisms. There are two separate push button switches in series, with the output of each of the four RTMs. Eight switch contacts are actuated through a mechanical linkage from a single push button. Pressing either push button will remove power from all four CRD trip breakers, initiating a reactor trip (Ref. 1).
APPLICABLE SAFETY ANALYSES	The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time. The Manual Reactor Trip channels are required as a backup to the automatic trip functions and allows operators to shut down the reactor whenever any parameter is rapidly trending toward its trip setpoint. The Manual Reactor Trip channels are retained for the overall redundancy and diversity of the RPS as required by the NRC.
LCO	The LCO on the RPS Manual Reactor Trip requires that the trip shall be OPERABLE whenever the reactor is critical or any time any control rod breaker is closed and rods are capable of being withdrawn, including shutdown bypass. This enables the operator to terminate any reactivity excursion that in the operator's judgment requires protective action, even if no automatic trip condition exists. The Manual Reactor Trip Function is composed of eight electrically independent trip switch contacts sharing a common mechanical push button. There are two separate push button switches, and both are required for the Manual Reactor Trip Function to be OPERABLE.

BASES

APPLICABILITY

The Manual Reactor Trip channels are required to be OPERABLE in MODES 1 and 2. They are also required to be OPERABLE in MODES 3, 4, and 5 if any CRD trip breaker is in the closed position and if the CRD System is capable of rod withdrawal. The only safety function of the RPS is to trip the CONTROL RODS; therefore, the Manual Reactor Trip channels are not needed in MODE 3, 4, or 5 if the reactor trip breakers are open or if the CRD System is incapable of rod withdrawal. Similarly, the RPS Manual Reactor Trip channels are not needed in MODE 6 when the CONTROL RODS are decoupled from the CRDs.

ACTIONS

A.1

Condition A applies when one Manual Reactor Trip channel is inoperable. A Completion Time of 48 hours is given to restore the Manual Reactor Trip channel to OPERABLE status. The 48 hour Completion Time is acceptable based on the redundant nature of the two Manual Reactor Trip channels.

B.1

Condition B applies when two Manual Reactor Trip channels are found inoperable. One hour is allowed to restore one channel to OPERABLE status. The automatic functions and various alternative manual trip methods, such as removing power to the RTMs, are still available. The 1 hour Completion Time is sufficient time to correct minor problems.

C.1 and C.2

With the Manual Reactor Trip channels inoperable and unable to be returned to OPERABLE status in MODE 1, 2, or 3, the unit must be placed in a condition in which manual trip is not required. Required Action C.1 and Required Action C.2 place the unit in at least MODE 3 with all CRD trip breakers open within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

D.1

With the Manual Reactor Trip channels inoperable and unable to be returned to OPERABLE status in MODE 4 or 5, the unit must be placed in a condition in which manual trip is not required. To achieve this status, all CRD trip breakers must be opened. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to open all CRD trip breakers without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the Manual Reactor Trip Function. This test verifies the OPERABILITY of the Manual Reactor Trip by actuation of the CRD trip breakers. The Frequency shall be once prior to each reactor startup (i.e., prior to each entry into MODE 2) if not performed within the preceding 7 days to ensure the OPERABILITY of the Manual Reactor Trip Function prior to achieving criticality. The Frequency was developed in consideration that these Surveillances are only performed during a unit outage.

REFERENCES

1. UFSAR, Section 7.2.

B 3.3 INSTRUMENTATION

B 3.3.3 Reactor Protection System (RPS) - Reactor Trip Module (RTM)

BASES

BACKGROUND

The RPS consists of four independent protection channels, each containing an RTM. Figure 7.2-1, UFSAR, Section 7.2 (Ref. 1), shows a typical RPS protection channel and the relationship of the RTM to the RPS instrumentation, manual trip, and CONTROL ROD drive (CRD) trip devices. The RTM receives bistable trip signals from the functions in its own channel and channel trip signals from the other three RPS - RTMs. The RTM provides these signals to its own two-out-of-four trip logic and transmits its own channel trip signal to the two-out-of-four logic of the RTMs in the other three RPS channels. Whenever any two RPS channels transmit channel trip signals, the RTM logic in each channel actuates to remove 120 VAC power from its associated CRD trip device.

The RPS trip scheme consists of series contacts that are operated by bistables. During normal unit operations, all contacts are closed and the RTM channel trip relay remains energized. However, if any trip parameter exceeds its setpoint, its associated contact opens, which de-energizes the channel trip relay.

When an RTM channel trip relay de-energizes, several things occur:

a. Each of the four (4) output logic relays "informs" its associated RPS channel that a reactor trip signal has occurred in the tripped RPS channel;

b. The contacts in the trip device circuitry, powered by the tripped channel, open, but the trip device remains energized through the closed contacts from the other RTMs. (This condition exists in each RPS - RTM. Each RPS - RTM controls power to a trip device.); and

c. The contact in parallel with the channel reset switch opens and the trip is sealed in. To re-energize the channel trip relay, the channel reset switch must be depressed after the trip condition has cleared.

When the second RPS channel senses a reactor trip condition, the output logic relays for the second channel de-energize and open contacts that supply power to the trip devices. With contacts opened by two separate RPS channels, power to the trip devices is interrupted and the CONTROL RODS fall into the core.

A minimum of two out of four RTMs must sense a trip condition to cause a reactor trip. Also, because the bistable relay contacts for each function are in series with the channel trip relays, two channel trips caused by different trip functions can result in a reactor trip.

BASES

APPLICABLE SAFETY ANALYSES

Accident analyses rely on a reactor trip for protection of reactor core integrity and reactor coolant pressure boundary integrity. A reactor trip must occur when needed to prevent accident conditions from exceeding those calculated in the accident analyses. More detailed descriptions of the applicable accident analyses are found in the bases for each of the RPS trip Functions in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

RTM response time is included in the overall required response time for each RPS trip and is not specified separately.

The RPS - RTMs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RTM LCO requires all four RTMs to be OPERABLE. Failure of any RTM renders a portion of the RPS inoperable and reduces the reliability of the affected Functions.

Four RTMs must be OPERABLE to ensure that a reactor trip would occur if needed any time the reactor is critical. OPERABILITY is defined as the RTM being able to receive and interpret trip signals from its own and other RPS channels and to open its associated trip devices (CRD trip breaker or SCR relays, as applicable).

The requirement of four channels to be OPERABLE ensures that no single RTM failure can preclude an RPS trip via the CRD trip breakers. Also, because of the logic arrangement of the CRD trip breakers (one-out-of-two taken twice) and arrangement of SCR trip channels, the requirement that four RTMs must be OPERABLE also ensures that a single RTM failure will not cause an unwanted reactor trip. Violation of this LCO could result in a trip signal not causing a reactor trip when needed.

APPLICABILITY

The RTMs are required to be OPERABLE in MODES 1 and 2. They are also required to be OPERABLE in MODES 3, 4, and 5 if any CRD trip breakers are in the closed position and the CRD System is capable of rod withdrawal. The RTMs are designed to ensure a reactor trip would occur, if needed, during these conditions. This condition can exist in all of these MODES; therefore, the RTMs must be OPERABLE.

ACTIONS

A.1.1, A.1.2, and A.2

When an RTM is inoperable, the associated CRD trip breaker must then be placed in a condition that is equivalent to a tripped condition for the RTM. Required Action A.1.1 or Required Action A.1.2 requires this either by tripping the CRD trip breaker or by removing power to the CRD trip breaker. Tripping (opening) the inoperable CRD trip breaker or removing power from the path containing the inoperable CRD trip breaker removes

BASES

ACTIONS

A.1.1, A.1.2, and A.2 (continued)

one source of power to the CRDs. Power to hold up control rods is still provided via the parallel CRD trip device(s). Therefore, a reactor trip will not occur until a trip occurs on the other trip pathway.

To ensure the trip signal is registered in the other channels, Required Action A.2 requires that the inoperable RTM be removed from the cabinet. This action causes the electrical interlocks to indicate a tripped channel in the remaining three RTMs. Operation in this condition is allowed indefinitely because the actions put the RPS into a one-out-of-three configuration. The 1 hour Completion Time is sufficient time to perform the Required Actions.

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

Condition B applies if any Required Action and associated Completion Time of Condition A is not met in MODE 1, 2, or 3 or if two or more RTMs are inoperable in MODE 1, 2, or 3. In this case, the unit must be placed in a condition in which the LCO does not apply. This is done by placing the unit in at least MODE 3 with all CRD trip breakers open or with power from all CRD trip breakers removed within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C applies if any Required Action and associated Completion Time of Condition A is not met in MODE 4 or 5 or if two or more RTMs are inoperable in MODE 4 or 5. In this case, the unit must be placed in a condition in which the LCO does not apply. This is done by opening all CRD trip breakers or removing power from all CRD trip breakers. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to open all CRD trip breakers or remove power from all CRD trip breakers without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1

The SRs include performance of a CHANNEL FUNCTIONAL TEST every 23 days on a STAGGERED TEST BASIS. This test shall verify the OPERABILITY of the RTM and its ability to receive and properly respond to channel trip and reactor trip signals. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Calculations have shown that the Frequency (23 days) maintains a high level of reliability of the Reactor Trip System in BAW-10167A, Supplement 3 (Ref. 2).

REFERENCES

1. UFSAR, Section 7.2, Figure 7.2-1.

2. BAW-10167A, Supplement 3, February 1998.

B 3.3 INSTRUMENTATION

B 3.3.4 CONTROL ROD Drive (CRD) Trip Devices

BASES

BACKGROUND

The Reactor Protection System (RPS) contains two types of CRD trip devices: four CRD trip breakers and two silicon controlled rectifier (SCR) relay trip channels. The system has two separate paths (or trip systems), with each path having two AC breakers in series. Each path provides independent power to the CRDs. Either path can provide sufficient power to operate the entire CRD System. SCRs are utilized in the CRD power supply to energize the CRD mechanism (CRDM) windings.

Figure 7.4-1, UFSAR, Section 7.4 (Ref. 1), illustrates the configuration of CRD trip devices. To trip the reactor, power to the CRDs must be removed. Loss of power causes the CRD's mechanisms to release the CONTROL RODS, which then fall by gravity into the core.

Power to CRDs is supplied from two separate unit sources through the AC trip circuit breakers. The CRD Control System trip system is designed so that when power is removed from the CRDM, the roller nuts disengage from the lead screw, and a free-fall gravity insertion of the control rods occurs. Two diverse and independent trip methods, in series, are provided for removal of power to the mechanisms. First, a trip is initiated when power is interrupted to the undervoltage coils of the main AC feeder breakers and to the undervoltage relays in the shunt trip circuits. Second, a trip is initiated when the gating signals to the SCRs are interrupted. Since parallel power feeds are provided, interruption of both feeds is required for trip action in either method of trip. Two diverse and independent methods of CRDM power interruption are provided in order to ensure that trip will occur when commanded.

The trip circuits consists of four independent RPS protective trip channels, four independent Anticipatory Reactor Trip System (ARTS) protective trip channels, and two manual reactor trip switches in series. The RPS protective trip channels are discussed in the Bases of LCO 3.3.3, "Reactor Protection System (RPS) - Reactor Trip Module (RTM)," while the manual trip switches are discussed in the Bases of LCO 3.3.2, "Reactor Protection System (RPS) Manual Reactor Trip." Each of the four RPS trip channels receives power from the RPS and is energized for the non-tripped (normal) condition. A channel is defined as tripped when it is de-energized.

The primary method of trip interrupts the three-phase AC power to the CRDM motor power supplies. Three-pole, metal-clad power circuit breakers equipped with instantaneous undervoltage coils and shunt trip devices are used as primary trip devices. Because two parallel power circuits feed the CRDM motor power supplies, two AC trip breakers are

BASES

BACKGROUND (continued)

provided in series in each feed. RPS Channel 2 energizes the undervoltage coil of breaker A and RPS Channel 4 energizes the undervoltage coil of breaker C to form the trip mechanism for the main bus (Channel A). RPS Channel 1 energizes the undervoltage coil of breaker B and RPS Channel 3 energizes the undervoltage coil of breaker D to form the trip mechanism for the secondary bus (Channel B). The trip breaker can remain closed only if its undervoltage coil is energized. Upon loss of voltage at the undervoltage coil due to interruption by an RPS, ARTS or manual trip signal, the breaker trips (opens). Each trip breaker's shunt trip circuit operates as follows. An undervoltage sensing relay is installed in parallel with the undervoltage coil of the trip breaker. A voltage sensing relay monitoring the undervoltage relay will cause it to energize the shunt trip device which is powered by 125 VDC, thereby tripping the breaker, as a diverse and redundant trip.

The second trip method interrupts the gate control signals to the SCRs in each of the sixty-one pairs of individual CRDM motor power supplies. The trip is provided by means of an electronic trip relay (K2) connected across the undervoltage device of trip breakers C and D. Loss of power to a K2 relay will cause a contact to open to notify the Control Rod Drive Control System (CRDCS) to degate the CRDM motor power supply SCRs through interrupting the gate control signals to the SCR's in each CRD motor power supply. When the gate signals are interrupted, the SCR's will revert to their open state on the next negative half-cycle of the applied AC voltage, thus removing all power at the outputs of the motor power supplies. Because the power supplies have redundant halves, two sets of SCR's for each CRDM motor power are provided. RPS Channel 3 provides the trip signal for one set of SCR's through the K2 relay in trip breaker D and RPS Channel 4 provides the trip signal for the other set of SCR's through the K2 relay in trip breaker C. The K2 trip relays and the associated SCR gate trip signals can remain in their non-tripped state only if the associated RPS channel is energized. When an RPS channel trips, the associated trip relays de-energize, interrupting the SCR gate control signals through the CRDCS controller.

APPLICABLE SAFETY ANALYSES

Accident analyses rely on a reactor trip for protection of reactor core integrity and reactor coolant pressure boundary integrity. A reactor trip must occur when needed to prevent accident consequences from exceeding those calculated in the accident analyses. The control rod insertion limits ensure that adequate rod worth is available upon reactor trip to shut down the reactor to the required SDM. Further, OPERABILITY of the CRD trip devices ensures that all CONTROL RODS will trip when required. More detailed descriptions of the applicable accident analyses are found in the Bases for each of the individual RPS

BASES

APPLICABLE SAFETY ANALYSES (continued)

trip Functions in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

The CRD trip devices satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires all of the CRD trip devices to be OPERABLE. Failure of any CRD trip device renders a portion of the RPS inoperable and reduces the reliability of the affected Functions. Without reliable CRD reactor trip circuit breakers and associated support circuitry, a reactor trip cannot occur when initiated either automatically or manually.

All CRD trip devices shall be OPERABLE to ensure that the reactor remains capable of being tripped any time it is critical. OPERABILITY is defined as the CRD trip device being able to receive a reactor trip signal and to respond to this trip signal by interrupting AC power to the CRDs. Both of the AC breaker's trip devices (undervoltage or shunt trip) and the breaker itself must be functioning properly for the AC breaker to be OPERABLE. Two SCR relay trip channels must be OPERABLE. Each SCR relay trip channel consists of the associated K2 relay and the CRDCS controller generated rod motor power supply SCR gating trip signals associated with all inservice individual rod power supplies.

Requiring four CRD trip breakers to be OPERABLE ensures that at least one device in each of the two power paths to the CRDs will remain OPERABLE even with a single failure. Requiring two SCR relay trip channels to be OPERABLE provides an additional method to interrupt power in each pathway to the CRDs. Requiring all devices OPERABLE also ensures that a single failure will not cause an unwanted reactor trip.

APPLICABILITY

The CRD trip devices shall be OPERABLE in MODES 1 and 2, and in MODES 3, 4, and 5 when any CRD trip breaker is in the closed position and the CRD System is capable of rod withdrawal.

The CRD trip devices are designed to ensure that a reactor trip would occur if needed any time the reactor is critical. Since this condition can exist in all of these MODES, the CRD trip devices shall be OPERABLE.

ACTIONS

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each CRD trip device.

A.1 and A.2

Condition A represents reduced redundancy in the CRD trip Function. Condition A applies when one diverse trip Function (undervoltage or shunt trip device) is inoperable in one or more CRD trip breaker(s).

BASES

ACTIONS

A.1 and A.2 (continued)

If one of the diverse trip Functions on a CRD trip breaker becomes inoperable, actions must be taken to preclude the inoperable CRD trip device from preventing a reactor trip when needed. This is done by manually tripping the inoperable CRD trip breaker or by removing power from the path containing the inoperable CRD trip breaker. Either of these actions places the affected CRDs in a one-out-of-two trip configuration, which precludes a single failure, which in turn could prevent tripping of the reactor. The 48 hour Completion Time has been shown to be acceptable through operating experience.

B.1 and B.2

Condition B represents a loss of redundancy for the CRD trip Function. Condition B applies when:

- One or more CRD trip breaker(s) will not function for reasons other than an inoperable undervoltage or shunt trip Function; or

- Both diverse trip Functions are inoperable in one or more CRD trip breaker(s).

Required Action B.1 and Required Action B.2 are the same as Required Action A.1 and Required Action A.2, but the Completion Time is shortened. The 1 hour Completion Time allowed to trip or remove power from the CRD trip breaker allows the operator to take all the appropriate actions for the inoperable breaker and still ensures that the risk involved is acceptable.

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

If any Required Action and associated Completion Time of Condition A or B is not met in MODE 1, 2, or 3, the unit must be brought to a condition in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3, with all CRD trip breakers open or with power from all CRD trip breakers removed within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS

D.1 and D.2

If any Required Action and associated Completion Time of Condition A or B is not met in MODE 4 or 5, the unit must be brought to a condition in which the LCO does not apply. To achieve this status, all CRD trip breakers must be opened or power from all CRD trip breakers removed within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to open all CRD trip breakers or remove power from all CRD trip breakers without challenging unit systems.

E.1

Condition E represents a loss of redundancy for the CRD trip Function. Condition E applies when one or both SCR relay channels are inoperable. The action is to restore the channel(s) to OPERABLE status prior to entering MODE 4, when in MODE 5 for ≥ 24 hours.

The Completion Time is acceptable because the CRD breakers are still available to trip the reactor on an RPS, ARTS, or Manual Trip signal.

Condition E is modified by a Note requiring Required Action E.1 to be completed whenever the Condition is entered. The Note is necessary to ensure the inoperable SCR(s) are restored to OPERABLE status when MODE 5 is entered for ≥ 24 hours.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 is to perform a CHANNEL FUNCTIONAL TEST of the CRD trip breakers every 23 days on a STAGGERED TEST BASIS. This test verifies the OPERABILITY of the trip devices by actuation of the end devices. Also, this test independently verifies the undervoltage and shunt trip mechanisms of the AC breakers. Calculations have shown that the Frequency (23 days) maintains a high level of reliability of the Reactor Trip System in BAW-10167A, Supplement 3 (Ref. 2).

SR 3.3.4.2

SR 3.3.4.2 is to perform a CHANNEL FUNCTIONAL TEST of the SCR relay trip channels every 24 months. This test verifies the OPERABILITY of the trip devices by actuation of the end devices. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 7.4, Figure 7.4-1.

2. BAW-10167A, Supplement 3, February 1998.

B 3.3 INSTRUMENTATION

B 3.3.5 Safety Features Actuation System (SFAS) Instrumentation

BASES

BACKGROUND

The SFAS initiates necessary safety systems, based on the values of selected unit Parameters, to automatically prevent or limit fission product and energy release from the core, to isolate the containment vessel, and to initiate the operation of Engineered Safety Features (ESF) equipment in the event of a loss-of-coolant accident (LOCA) and main steam line break (MSLB).

SFAS actuates the following systems:

- High pressure injection (HPI);
- Low pressure injection (LPI);
- Containment air cooling;
- Containment spray;
- Containment isolation;
- Emergency diesel generator (EDG).

SFAS also actuates other systems and components. A detailed list of systems and components actuated by each SFAS Parameter is identified in the UFSAR, Table 7.3-2 (Ref. 1) and UFSAR, Figures 7.3-1 through 7.3-8 (Ref. 2).

The SFAS operates in a distributed manner to initiate the appropriate systems. The SFAS does this by determining the need for actuation in each of four channels monitoring each actuation Parameter. Once the need for actuation is determined, the condition is transmitted to automatic actuation logics, which perform the two-out-of-four logic to determine the actuation of each end device.

Four Parameters are used for automatic actuation:

- Reactor Coolant System (RCS) Pressure - Low;
- RCS Pressure - Low Low;
- Containment Pressure - High; and
- Containment Pressure - High High.

BASES

BACKGROUND (continued)

A fifth parameter, Borated Water Storage Tank Level - Low Low, is used to provide a permissive to allow manual transfer to the containment sump.

LCO 3.3.5 covers only the instrumentation channels that measure these Parameters. These channels include all intervening equipment necessary to produce actuation before the measured process Parameter exceeds the limits assumed by the accident analysis. This includes sensors, bistable devices, and operational bypass circuitry. LCO 3.3.6, "Safety Features Actuation System (SFAS) Manual Initiation," and LCO 3.3.7, "Safety Features Actuation System (SFAS) Automatic Actuation Logic," provide requirements on manual initiation and automatic actuation logic.

The SFAS consists of four identical redundant instrument (sensing) and logic channels and two identical redundant actuation channels. Each instrument channel includes analog circuits with analog isolation devices, and trip bistable modules with digital (optical electronic) isolation devices. The isolated output of the trip bistable module is used to comprise coincidence matrices with the terminating relays within the actuation channel of SFAS. The isolation devices also provide isolation between channels. The trip bistables in each of the four sensing channels provide inputs to the corresponding output modules of their logic channels and the output modules of the remaining three logic channels. Should any two out of four trip bistables monitoring a given variable trip, the output modules in all four logic channels connected to that trip bistable will trip. The terminating (output) relays de-energize when the associated output module trips. The terminating relays of instrumentation and logic channels 1 and 3, must both be de-energized to activate SFAS actuation channel 1. Similarly, instrumentation and logic channels 2 and 4 are de-energized to activate SFAS actuation channel 2. The terminating relays act on the actuation control devices such as motor controllers and solenoid valves. Figures 7.3-1 and 7.3-2, UFSAR, Section 7.3.1.1.2 (Ref. 3), illustrates how instrumentation channel trips combine to cause protection channel trips.

The equipment actuation by SFAS depends upon the severity of the accident, as indicated by the sensor channels. The actuated equipment is separated into five Incident Levels. A brief description of the five SFAS Incident Levels follows. Note that the listings of the actuated equipment are a summary. A complete listing is provided in UFSAR, Figures 7.3-3 through 7.3-8 (Ref. 2).

BASES

BACKGROUND (continued)

An Incident Level 1 actuation will occur when the RCS Pressure - Low or Containment Pressure - High setpoint is reached. The Containment Purge and Exhaust and Containment Sampling Systems are isolated, the Station Emergency Ventilation System is actuated, and the Control Room Normal Ventilation System is isolated.

An Incident Level 2 actuation also occurs when the RCS Pressure - Low or Containment Pressure - High setpoint is reached. High pressure injection is initiated, the Component Cooling Water System, Service Water System, containment air coolers, and emergency diesel generators are started, various containment isolation valves are closed, and the containment spray valves are opened (although containment spray pumps are not started).

An Incident Level 3 actuation occurs when the RCS Pressure - Low Low or Containment Pressure - High setpoint is reached. Low pressure injection is initiated and additional containment isolation valves are closed.

An Incident Level 4 actuation occurs when the Containment Pressure - High High setpoint is reached. The Containment Spray System is started and additional containment isolation valves are closed.

An Incident Level 5 actuation occurs when the BWST Level - Low Low setpoint is reached, indicating that the BWST has been nearly depleted. A permissive is generated to allow manual transfer to the containment emergency sump.

The SFAS will automatically sequence the protective action by loading equipment in steps if the normal or reserve power is not available. Each logic channel has one sequencer module. One of the SFAS actions during an Incident Level 2 is to start the EDG. In the event of a loss of offsite power concurrent with an SFAS trip, the EDGs will energize the 4.16 kV buses, and the SFAS sequencers will sequence the SFAS initiated loads onto the diesel generator. LCO 3.3.8, "Emergency Diesel Generator (EDG) Loss of Power Start (LOPS)," contains the requirements for the undervoltage channels.

The ESF equipment is divided between the two redundant actuation trains 1 and 2. The division of the equipment between the two actuation trains is based on the equipment redundancy and function and is accomplished in such a manner that the failure of one of the actuation channels and the related safeguards equipment will not inhibit the overall ESF Functions. Redundant ESF equipment is controlled from separate and independent actuation channels.

BASES

BACKGROUND (continued)

The actuation of ESF equipment is also available by manual actuation switches located on the control room console.

The SFAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents (DBAs), specifically the loss of coolant accident (LOCA) and main steam line break (MSLB) events. The SFAS relies on the OPERABILITY of the automatic actuation logic for each component to perform the actuation of the selected systems of LCO 3.3.7.

Safety Features Actuation System Bypasses

SFAS includes channel bypasses, operating bypasses, and shutdown bypasses. Each SFAS instrument and logic channel is provided with one key operated test trip bypass switch. This switch enables the operator to change the two-out-of-four coincidence matrices into a two-out-of-three mode for one Parameter. In effect the operator may bypass one channel of either RCS pressure, Containment Pressure, and BWST level. These channel bypasses permit test, calibration, or maintenance of the SFAS transmitters. Operational bypass of certain channels is necessary to allow reactor shutdown without undesired SFAS actuation.

The SFAS RCS pressure instrumentation channels include permissive bistables that allow manual bypass when reactor pressure is below the point at which the low and low low pressure trips are required to be OPERABLE. Once permissive conditions are sensed, the RCS pressure trips may be manually bypassed. Bypasses are automatically removed before pressure reaches the point at which they are required to be OPERABLE.

Components can be blocked to allow for accident recovery actions. This is accomplished by manually blocking the associated output logic modules from switches located on control room panels.

The shutdown bypass is provided to prevent spurious actuation of the SFAS and is only allowed to be used in MODES 5 and 6 or when the core is defueled.

Reactor Coolant System Pressure

The RCS pressure is monitored by four independent pressure transmitters located in the containment. These transmitters are separate from the transmitters that feed the Reactor Protection System (RPS). Each of the pressure signals generated by these transmitters is monitored

BASES

BACKGROUND (continued)

by four bistables to provide two trip signals, one at low pressure and the other at low-low pressure, and two bypass permissive signals, one at low pressure and one at low-low pressure.

Containment Pressure

Containment pressure is monitored by four independent pressure transmitters located in the auxiliary building. These transmitters are separate from the pressure switches that feed the Reactor Protection System (RPS). Each of the pressure signals generated by these transmitters is monitored by two bistables to provide two trip signals, one at high pressure and the other at high high pressure.

Borated Water Storage Tank Level

Borated water storage tank level is monitored by four independent level transmitters (differential cell design). Each of the differential pressure signals generated by these transmitters is monitored by a bistable to provide a trip signal at a low low level.

Trip Setpoints and Allowable Values

Trip setpoints are the nominal value at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.

The trip setpoints used in the bistables are based on the analytical limits stated in setpoint calculations. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing uncertainties are taken into account. To allow for calibration tolerances, instrumentation uncertainties, and instrument drift that are not present or are not measured during CHANNEL FUNCTIONAL TESTS, and severe environment induced errors for those SFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4), the Allowable Values specified in Table 3.3.5-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. The trip setpoint is established using Method 1 or Method 2 of Reference 5 or 6. The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST. One example of such a change in measurement error is drift during the surveillance interval. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

BASES

BACKGROUND (continued)

Setpoints, in accordance with the Allowable Values, ensure that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel can be tested online to verify that the setpoint accuracy is within the specified allowance requirements of the setpoint calculation. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated.

The Allowable Values listed in Table 3.3.5-1 are established using Method 1 or Method 2 of Reference 5 or 6, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each trip setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

APPLICABLE SAFETY ANALYSES

The following SFAS Functions have been assumed within the accident analyses.

High Pressure Injection

The SFAS actuation of HPI has been assumed for core cooling in the LOCA analysis and is credited with boron addition in the MSLB analysis.

Low Pressure Injection

The SFAS actuation of LPI has been assumed for LOCAs.

Containment Spray, Containment Cooling, and Containment Isolation

The SFAS actuation of the containment air coolers and containment spray have been credited in containment analysis for LOCAs, both for containment performance and equipment environmental qualification pressure and temperature envelope definition. Accident dose calculations have credited containment isolation and containment spray.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Emergency Diesel Generator Start

The SFAS initiated EDG start has been assumed in the LOCA analysis to ensure that emergency power is available throughout the limiting LOCA scenarios.

The small and large break LOCA analyses assume a conservative delay time for the actuation of HPI and LPI in UFSAR, Section 6.3 (Ref. 7). This delay time includes allowances for EDG starting, EDG loading, Emergency Core Cooling Systems (ECCS) pump starts, and valve openings. Similarly, the containment air cooling, containment isolation, and containment spray have been analyzed with delays appropriate for the entire system analyzed.

Accident analyses rely on automatic SFAS actuation for protection of the core temperature and containment pressure limits and for limiting off site dose levels following an accident. These include LOCA and MSLB events that result in RCS inventory reduction.

The SFAS channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires four channels of SFAS instrumentation for each Parameter in Table 3.3.5-1 to be OPERABLE in each SFAS train. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Parameter and affected systems or components.

Only the Allowable Value is specified for each SFAS Function in the LCO. Nominal trip setpoints are specified in the unit specific setpoint calculations. The nominal trip setpoints are selected to ensure the setpoints measured by CHANNEL FUNCTIONAL TESTS do not exceed the Allowable Value if the bistable is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable provided that operation and testing are consistent with the assumptions of the unit specific setpoint calculations. Each Allowable Value specified is more conservative than the analytical limit assumed in the safety analysis to account for instrument uncertainties appropriate to the trip Parameter. These uncertainties are defined in the setpoint calculations. The Allowable Values are specified for the CHANNEL FUNCTIONAL TEST.

BASES

LCO (continued)

The Allowable Values for bypass removal functions are stated in the Applicable MODES or Other Specified Condition column of Table 3.3.5-1.

Four SFAS instrumentation channels shall be OPERABLE for each Parameter. Failure of any channel reduces the reliability of the affected Parameter.

The bases for the LCO on SFAS Parameters include the following.

Reactor Coolant System Pressure

Four channels each of RCS Pressure - Low and RCS Pressure - Low Low are required OPERABLE. Each channel includes a sensor, trip bistable, and block permissive bistable. The analog portion of each pressure channel is common to both RCS Pressure Parameters. Therefore, failure of one analog channel renders one channel of the low pressure and low low pressure Parameters inoperable.

1. Reactor Coolant System Pressure - Low

   The RCS Pressure - Low is based on HPI actuation for small break LOCAs. The Allowable Value of ≥ 1576.2 psig ensures that the HPI will be actuated at a pressure greater than or equal to the value assumed in accident analyses. The RCS Pressure instrumentation must function while subject to the severe environment created by a LOCA. Therefore, the Allowable Value accounts for severe environment induced errors.

   To ensure the RCS Pressure - Low trip is not bypassed when required to be OPERABLE by the safety analysis, each channel's block permissive bistable must be set with a reset Allowable Value of ≤ 1800 psig. The block permissive does not need to function for accidents initiated from RCS Pressures below the block permissive setpoint. Therefore, the bypass removal Allowable Value need not account for severe environment induced errors.

2. Reactor Coolant System Pressure - Low Low

   The RCS Pressure - Low Low is selected to occur in sufficient time to ensure LPI flow prior to the emptying of the core flood tanks during a large break LOCA. The Allowable Value of ≥ 441.42 psig ensures sufficient overlap of the core flood tank flow and the LPI flow to keep the reactor vessel downcomer full during a large break LOCA. The RCS Pressure instrumentation must function while subject to the severe environment created by a LOCA. Therefore, the Allowable Value accounts for severe environment induced errors.

BASES

LCO (continued)

To ensure the RCS Pressure - Low Low trip is not bypassed when assumed OPERABLE by the safety analysis, each channel's block permissive bistable must be set with a reset Allowable Value of ≤ 660 psig. The block permissive does not need to function for accidents initiated by RCS Pressure below the block permissive setpoint. Therefore, the block permissive setpoint Allowable Value need not account for severe environment induced errors.

Containment Pressure

Four channels each of Containment Pressure - High and Containment Pressure - High High are required to be OPERABLE in each train. Each channel includes a sensor and trip bistable. The analog portion of each containment pressure channel is common to both Containment Pressure Parameters. Therefore, failure of one analog channel renders one channel of Containment Pressure - High and Containment Pressure - High High Parameters inoperable.

1. Containment Pressure - High

   The Containment Pressure - High Allowable Value of ≤ 19.38 psia was selected to be low enough to detect a rise in containment pressure that would occur due to a small break LOCA, thus ensuring that the containment high pressure actuation of the safety systems will occur for a wide spectrum of break sizes. The trip also causes the containment coolers to shift to low speed to prevent damage to the cooler fans due to the increase in the density of the air steam mixture present in the containment following a LOCA.

2. Containment Pressure - High High

   The Containment Pressure - High High Allowable Value of ≤ 41.65 psia was chosen to be low enough to ensure a timely actuation during a large break LOCA.

Borated Water Storage Tank - Low Low

The Borated Water Storage Tank Allowable Value of ≥ 101.6 inches of water and ≤ 115.4 inches of water was chosen to provide the operator with an alarm and a permissive to allow timely operation of the borated water storage tank (BWST) outlet and containment emergency sump valves to the long term recirculation position. This is to protect the pumps from cavitation for lack of proper net positive suction head and allow

BASES

LCO (continued)

transfer of ECCS suction to the containment emergency sump from the BWST during the recirculation mode of operation before the inventory of the BWST is depleted.

APPLICABILITY

Four channels of SFAS instrumentation for each Parameter listed next shall be OPERABLE.

1. Reactor Coolant System Pressure - Low

   The RCS Pressure - Low Setpoint Parameter shall be OPERABLE in MODE 1 and 2 and in MODE 3 with RCS pressure at and above 1800 psig. This requirement ensures the capability to automatically actuate safety systems and components during conditions indicative of a LOCA or secondary unit overcooling. Below 1800 psig, the low RCS Pressure actuation Parameter can be bypassed to avoid actuation during normal unit cooldowns when safety system actuations are not required.

   The allowance for the bypass is consistent with the transition of the unit to a lower energy state, providing greater margins to safety limits. The unit response to any event, given that the reactor is already tripped, will be less severe and allows sufficient time for operator action to provide manual safety system actuations. This is even more appropriate during unit heatups when the primary system and core energy content is low, prior to power operation.

   In MODE 3 below 1800 psig, and in MODES 4, 5, and 6, there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low, and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

2. Reactor Coolant System Pressure - Low Low

   The RCS Pressure - Low Low Setpoint Parameter shall be OPERABLE during operation above 660 psig. This requirement ensures the capability to automatically actuate safety systems and components during conditions indicative of a LOCA or secondary unit overcooling. Below 660 psig, the low low RCS pressure actuation Parameter can be bypassed to avoid actuation during normal unit cooldowns when safety system actuations are not required.

BASES

APPLICABILITY (continued)

The allowance for the bypass is consistent with the transition of the unit to a lower energy state, providing greater margins to safety limits. The unit response to any event, given that the reactor is already tripped, will be less severe and allows sufficient time for operator action to provide manual safety system actuations. This is even more appropriate during unit heatups when the primary system and core energy content is low, prior to power operation.

In MODE 3 with RCS pressure below 660 psig, and in MODES 4, 5, and 6, there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low, and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

3. 4. Containment Pressure - High and Containment Pressure - High High

The Containment Pressure - High and Containment Pressure - High High Parameter shall be OPERABLE in MODES 1, 2, 3, and 4 when the potential for a HELB exists. In MODES 5 and 6, the unit conditions are such that there is insufficient energy in the primary and secondary systems to raise the containment pressure to either the Containment Pressure - High or Containment Pressure - High High Setpoints. Furthermore, in MODES 5 and 6, there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Plant pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

5. Borated Water Storage Tank - Low Low

The Borated Water Storage Tank - Low Low shall be OPERABLE in MODES 1, 2, 3, and 4 when the potential for a LOCA exists. In MODES 5 and 6, the BWST does not support any equipment required to be OPERABLE, therefore the Borated Water Storage Tank - Low Low Function is not required to be OPERABLE.

BASES

ACTIONS

Required Actions A and B apply to all SFAS instrumentation Parameters listed in Table 3.3.5-1.

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each Parameter.

If a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or SFAS bistable is found inoperable, then all affected functions provided by that channel should be declared inoperable and the unit must enter the Conditions for the particular protection Parameter affected.

A.1

Condition A applies when one channel becomes inoperable in one or more Parameters. If one SFAS channel is inoperable, placing it in a tripped condition leaves the system in a one-out-of-three condition for actuation. Thus, if another channel were to fail, the SFAS instrumentation could still perform its actuation functions. This action is completed when all of the affected logic inputs are tripped. This can normally be accomplished by tripping the affected bistables.

The 1 hour Completion Time is sufficient time to perform the Required Action.

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

Condition B applies when the Required Action and associated Completion Time of Condition A is not met or when one or more parameters have more than one inoperable channel. If Condition B applies, the unit must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and, for the RCS Pressure - Low channels, to < 1800 psig, for the RCS Pressure - Low Low channels, to < 660 psig, and for the Containment Pressure High channels and High High channels, to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

The SRs for each SFAS instrumentation Parameter are identified by the SRs column of Table 3.3.5-1 for that Parameter.

SR 3.3.5.1

Performance of the CHANNEL CHECK every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the transmitter or the signal processing equipment has drifted outside its limit.

The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel operability during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2

The Surveillance is modified by a Note that states when an SFAS channel is placed in an inoperable status solely for performance of this Surveillance, entry into the associated Conditions and Required Actions may be delayed for up to 8 hours, provided two other channels of the same SFAS instrumentation Parameter are OPERABLE. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This is acceptable since the other two required channels will continue to ensure the associated SFAS Parameter can perform its assumed function. This allowance is based on the inability to perform the Surveillance in the time permitted by the Required Actions. Eight hours is the average time required to perform

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

the Surveillance. It is not acceptable to routinely remove channels from service for more than 8 hours to perform required Surveillance testing.

A CHANNEL FUNCTIONAL TEST is performed on each required SFAS channel to ensure the entire channel will perform the intended functions. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current unit specific setpoint analysis. The CHANNEL FUNCTIONAL TEST of the RCS Pressure – Low and – Low Low instrumentation includes the logic for the RCS pressure operating bypasses.

The Frequency of 31 days is based on unit operating experience, with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is a rare event.

SR 3.3.5.3 and SR 3.3.5.4

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the unit specific setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint analysis. The CHANNEL CALIBRATION of the RCS Pressure – Low and – Low Low instrumentation includes the RCS pressure operating bypass function.

This Frequency of SR 3.3.5.3 is justified by the assumption of an 18 month calibration interval to determine the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.5.4 is justified by the assumption of a 24 month calibration interval to determine the magnitude of equipment drift in the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.5

SR 3.3.5.5 ensures that the SFAS actuation channel response times are less than or equal to the maximum times assumed in the accident analysis. The response time values are the maximum values assumed in the safety analyses. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time from the point at which the parameter exceeds the actuation setpoint value at the sensor to the point at which the end device is actuated. Thus, this SR encompasses the automatic actuation logic components covered by LCO 3.3.7 and the operation of the mechanical ESF components. Response time testing acceptance criteria for this unit are included in Reference 8.

Response time tests are conducted on an 24 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 month test Frequency is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation but not channel failure are infrequent occurrences.

REFERENCES

1. UFSAR, Table 7.3-2.
2. UFSAR, Figures 7.3-1 through 7.3-8.
3. UFSAR, Section 7.3.1.1.2.
4. 10 CFR 50.49.
5. ISA RP 67.04-Part II - 1994, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."
6. ISA RP 67.04.02 - 2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."
7. UFSAR, Section 6.3.
8. Technical Requirements Manual.

B 3.3 INSTRUMENTATION

B 3.3.6 Safety Features Actuation System (SFAS) Manual Initiation

BASES

BACKGROUND

The SFAS manual initiation capability allows the operator to actuate SFAS Functions from the main control room in the absence of any other initiation condition. One set of control switches (push button) will actuate Incident Levels 1 through 4, except for the containment spray pumps and containment spray discharge valves. These switches do not provide a signal to Incident Level 5 components (borated water storage tank suction valves and emergency sump). These manual initiation channels will be referred to as the SFAS manual initiation channels. Another set of control switches will only initiate the containment spray pumps and containment spray discharge valves. These manual initiation channels will be referred to as the Containment Spray System manual initiation channels. This SFAS manual initiation capability is provided in the event the operator determines that an SFAS Function is needed and has not been automatically actuated. Furthermore, the SFAS manual initiation capability allows operators to rapidly initiate Engineered Safety Features (ESF) Functions if the trend of unit parameters indicates that ESF actuation will be needed.

LCO 3.3.6 covers only the SFAS manual initiation channels and the Containment Spray System manual initiation channels. LCO 3.3.5, "Safety Features Actuation System (SFAS) Instrumentation," and LCO 3.3.7, "Safety Features Actuation System (SFAS) Automatic Actuation Logic," provide requirements on the portions of the SFAS that automatically initiate the Functions described earlier.

The SFAS manual initiation Function relies on the OPERABILITY of the automatic actuation logic (LCO 3.3.7) for each component to perform the actuation of the systems. A manual trip push button is provided on the ESF panel of the control room console for each SFAS manual initiation channels and the Containment Spray System manual initiation channels. Operation of a control switch will provide inputs to the output modules which de-energize relays to actuate the associated equipment.

The SFAS manual initiation channel is defined as the instrumentation between the control switch and the automatic actuation logic, which actuates the end devices. Other means of manual initiation, such as controls for individual ESF devices, may be available in the control room and other unit locations. These alternative means are not required by this LCO, nor may they be credited to fulfill the requirements of this LCO.

BASES

APPLICABLE SAFETY ANALYSES	The SFAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents, specifically, the loss of coolant accident and main steam line break events. The SFAS manual initiation ensures that the control room operator can rapidly initiate ESF Functions at any time. The manual initiation trip Function is required as a backup to automatic trip functions and allows operators to initiate SFAS whenever any parameter is rapidly trending toward its trip setpoint. Furthermore, the SFAS manual initiation may be specified in operating procedures for verification of ESF actuation. The SFAS manual initiation functions satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two SFAS manual initiation channels of each SFAS Function shall be OPERABLE whenever conditions exist that could require ESF protection of the reactor or containment. Two OPERABLE channels of SFAS manual initiation and two OPERBLE channels for Containment Spray manual initiation ensure that no single random failure will prevent system level manual initiation of any required SFAS Function. The SFAS manual initiation Function allows the operator to initiate protective action prior to automatic initiation or in the event the automatic initiation does not occur.
APPLICABILITY	The SFAS manual initiation Functions shall be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the associated engineered safety features equipment is required to be OPERABLE. The manual initiation channels are required because ESF Functions are designed to provide protection in these MODES. In MODES 5 and 6, SFAS initiates systems that are either reconfigured or disabled for shutdown cooling operation. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components. Adequate time is available to evaluate unit conditions and to respond by manually operating the ESF components, if required.
ACTIONS	A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each SFAS manual initiation Function. <u>A.1</u> Condition A applies when one manual initiation channel of one or more SFAS Functions becomes inoperable. Required Action A.1 must be taken to restore the channel to OPERABLE status within the next 72 hours. The Completion Time of 72 hours is based on unit operating experience and administrative controls, which provide alternative means

BASES

ACTIONS

A.1 (continued)

of SFAS Function initiation via individual component controls. The 72 hour Completion Time is consistent with the allowed outage time for the safety systems actuated by SFAS (i.e., Required Action B.1 in LCO 3.5.2, "Emergency Core Cooling System - Operating").

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the SFAS manual initiation. This test verifies that the initiating circuitry is OPERABLE and will actuate the end device (i.e., pump, valves, etc.). The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency is demonstrated to be sufficient, based on operating experience, which shows these components usually pass the Surveillance when performed on the 24 month Frequency.

REFERENCES

None.

B 3.3 INSTRUMENTATION

B 3.3.7 Safety Features Actuation System (SFAS) Automatic Actuation Logic

BASES

BACKGROUND

The automatic actuation logic channels of SFAS are defined as the logic between the buffers of the sensing channels and the controllers that actuate SFAS equipment. Each of the components actuated by the SFAS Functions has an associated automatic actuation logic. If two-out-of-four SFAS instrumentation channels indicate a trip, or system level manual initiation occurs, the automatic actuation logic is activated and the associated component is actuated. The purpose of requiring OPERABILITY of the SFAS automatic actuation logic is to ensure that the Functions of the SFAS can be automatically initiated in the event of an accident. Automatic actuation of some Functions is necessary to prevent the unit from exceeding the Emergency Core Cooling Systems (ECCS) limits in 10 CFR 50.46 (Ref. 1). It should be noted that OPERABLE automatic actuation logic channels alone will not ensure that each Function can be activated; the instrumentation channels and actuated equipment associated with each Function must also be OPERABLE to ensure that the Functions can be automatically initiated during an accident.

The SFAS consists of four identical redundant instrument (sensing) and logic channels and two identical redundant actuation channels. Each instrument channel includes analog circuits with analog isolation devices and trip bistable modules with digital (optical electronic) isolation devices. The isolated output of the trip bistable module is used to comprise coincidence matrices with the terminating relays within the actuation channel of SFAS. The isolation devices also provide isolation between channels. The trip bistables in each of the four sensing channels provide inputs to the corresponding output modules of their logic channels and the output modules of the remaining three logic channels. Should any two out of four trip bistables monitoring a given variable trip, the output modules in all four logic channels connected to that trip bistable will trip. The terminating (output) relays de-energize when the associated output module trips. The terminating relays of instrumentation and logic channels 1 and 3, must both be de-energized to activate SFAS actuation channel 1. Similarly, instrumentation and logic channels 2 and 4 are de-energized to activate SFAS actuation channel 2. The terminating relays act on the actuation control devices such as motor controllers and solenoid valves. Figure 7.3-2, UFSAR, Section 7.3.1.1.2 (Ref. 2), illustrates how instrumentation channel trips combine to cause protection channel trips.

BASES

BACKGROUND (continued)

The equipment actuation by SFAS depends upon the severity of the accident, as indicated by the sensor channels. The actuated equipment is separated into five Incident Levels. A brief description of the five SFAS Incident Levels follows. Note that the listings of the actuated equipment are a summary. A complete listing is provided in UFSAR Figures 7.3-3 through 7.3-8.

An Incident Level 1 actuation will occur when the RCS Pressure - Low or Containment Pressure - High setpoint is reached. The Containment Purge and Exhaust and Containment Sampling Systems are isolated, the Station Emergency Ventilation System is actuated, and the Control Room Normal Ventilation System is isolated.

An Incident Level 2 actuation also occurs when the RCS Pressure - Low or Containment Pressure - High setpoint is reached. High pressure injection is initiated, the Component Cooling Water System, Service Water System, containment air coolers, and emergency diesel generators are started, various containment isolation valves are closed, and the containment spray valves are opened (although containment spray pumps are not started).

An Incident Level 3 actuation occurs when the RCS Pressure - Low Low or Containment Pressure - High setpoint is reached. Low pressure injection is initiated and additional containment isolation valves are closed.

An Incident Level 4 actuation occurs when the Containment Pressure - High High setpoint is reached. The Containment Spray System is started and additional containment isolation valves are closed.

An Incident Level 5 actuation occurs when the BWST Level - Low Low setpoint is reached, indicating that the BWST has been nearly depleted. A permissive is generated to allow manual transfer to the containment emergency sump.

LCO 3.3.7 covers only the automatic actuation logic that initiates these Functions. LCO 3.3.5, "Safety Features Actuation System (SFAS) Instrumentation," and LCO 3.3.6, "Safety Features Actuation System (SFAS) Manual Initiation," provide requirements on the instrumentation and manual initiation channels that input to the automatic actuation logic.

The SFAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents (DBAs), specifically, the loss of coolant accident (LOCA) and main steam

BASES

BACKGROUND (continued)

line break (MSLB) events. The SFAS relies on the OPERABILITY of the automatic actuation logic for each component to perform the actuation of the selected systems.

The small and large break LOCA analyses assume a conservative delay time for the actuation of high pressure injection (HPI) and low pressure injection (LPI) in UFSAR Section 6.3 (Ref. 2). This delay time includes allowances for emergency diesel generator (EDG) starts, EDG loading, ECCS pump starts, and valve openings. Similarly, the containment air cooling, containment isolation, and containment spray have been analyzed with delays appropriate for the entire system.

The SFAS automatic initiation of Engineered Safety Feature (ESF) Functions to mitigate accident conditions is assumed in the DBA analysis and is required to ensure that consequences of analyzed events do not exceed the accident analysis predictions. Automatically actuated features include HPI, LPI, containment air cooling, containment spray, and containment isolation.

APPLICABLE SAFETY ANALYSES

Accident analyses rely on automatic SFAS actuation for protection of the core and containment and for limiting off site dose levels following an accident. These include LOCA and MSLB events that result in Reactor Coolant System (RCS) inventory reduction. The automatic actuation logic is an integral part of the SFAS.

The SFAS automatic actuation logics satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The automatic actuation output logic for each component actuated by the SFAS is required to be OPERABLE whenever conditions exist that could require ESF protection of the reactor or the containment. This ensures automatic initiation of the ESF required to mitigate the consequences of accidents.

APPLICABILITY

The automatic actuation output logic Function shall be OPERABLE in MODES 1, 2, and 3, and in MODE 4 when the associated engineered safety features equipment is required to be OPERABLE, because ESF Functions are designed to provide protection in these MODES. Automatic actuation in MODE 5 or 6 is not required because the systems initiated by the SFAS are either reconfigured or disabled for shutdown cooling operation. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components. Adequate time is available to evaluate unit conditions and respond by manually operating the ESF components, if required.

BASES

ACTIONS

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each SFAS automatic actuation output logic.

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

When one or more automatic actuation output logics are inoperable, either the output logic may be tripped or the associated component(s) can be placed in its engineered safety features configuration. Required Action A.1 places the associated output logic in its actuated condition while Required Action A.2 is equivalent to the automatic actuation output logic performing its safety function ahead of time. In some cases, placing the component in its engineered safety features configuration would violate unit safety or operational considerations. In these cases, the component status should not be changed, but the supported system component must be declared inoperable. Conditions which would preclude the placing of a component in its engineered safety features configuration include, but are not limited to, violation of system separation, activation of fluid systems that could lead to thermal shock, or isolation of fluid systems that are normally functioning. The Completion Time of 1 hour is based on operating experience and reflects the urgency associated with the inoperability of a safety system component.

Required Action A.3 requires entry into the Required Actions of the affected supported systems, since the true effect of automatic actuation logic failure is inoperability of the supported system. The Completion Time of 1 hour is based on operating experience and reflects the urgency associated with the inoperability of a safety system component.

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1

SR 3.3.7.1 is the performance of a CHANNEL FUNCTIONAL TEST on a 31 day STAGGERED TEST BASIS. The test demonstrates that every automatic actuation logic associated with one of the two safety actuation trains successfully performs the two-out-of-four logic combinations every 31 days. All automatic actuation logics are thus retested every 62 days. The test simulates the required one-out-of-four inputs to the logic circuit and verifies the successful operation of the automatic actuation logic. The Frequency is based on operating experience that demonstrates the rarity of more than one channel failing within the same 31 day interval.

Automatic actuation logic response time testing is incorporated into the response time testing required by LCO 3.3.5.

REFERENCES

1. 10 CFR 50.46.

2. UFSAR, Section 6.3.

B 3.3 INSTRUMENTATION

B 3.3.8 Emergency Diesel Generator (EDG) Loss of Power Start (LOPS)

BASES

BACKGROUND

The EDGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate a LOPS in the event a loss of voltage or degraded voltage condition occurs in the switchyard. There are two LOPS Functions for each 4.16 kV vital bus.

Four undervoltage relays with time delays are provided on each 4.16 kV essential bus for the purpose of detecting a loss of voltage condition. Two undervoltage relays and an auxiliary relay per essential bus are associated with a channel. Either undervoltage relay in a channel will actuate its associated auxiliary relay. The actuation of both auxiliary relays (two-out-of-two logic) will disconnect the offsite source, load shed the essential bus, and generate an EDG LOPS.

Four undervoltage relays with time delays are provided on each 4.16 kV essential bus for the purpose of detecting a sustained undervoltage condition (degraded voltage condition). Two undervoltage relays and an auxiliary relay per essential bus are associated with a channel. Either undervoltage relay in a channel will actuate its associated auxiliary relay. The actuation of both auxiliary relays (two-out-of-two logic) will disconnect the offsite source. Disconnecting the offsite source causes the loss of voltage relays to actuate. As described above, the loss of voltage relays will disconnect the offsite source, load shed the essential bus, and generate an EDG LOPS. The LOPS initiated ACTIONS are described in UFSAR, Section 8.3.1.1 (Ref. 1).

Trip Setpoints and Allowable Value

The trip setpoints used in the relays are based on the analytical limits. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The actual relay trip setpoint is more conservative than that required by the unit specific setpoint calculations. A channel is inoperable if its actuation trip setpoint is not within its required Allowable Value.

The undervoltage protection scheme has been designed to protect the unit from spurious trips caused by the offsite power source. This is made possible by the time delay characteristics of the relays used. A complete loss of offsite power will result in approximately a 10 second interruption of the power supply. The EDG starts and is available to accept loads within a 10 second time interval on the Safety Features Actuation System

BASES

BACKGROUND (continued)

(SFAS) or LOPS. Emergency power is established within the maximum time delay assumed for each event analyzed in the accident analysis (Ref. 2).

With two protection channels in a one-out-of-two, taken twice trip logic for each essential bus of the 4.16 kV power supply, no single failure will cause or prevent protective system actuation. This arrangement meets IEEE-279-1971 criteria (Ref. 3).

APPLICABLE SAFETY ANALYSES

The EDG LOPS is required for the Engineered Safety Features (ESF) to function in any accident with a loss of offsite power. Its design basis is that of the SFAS.

Accident analyses credit the loading of the EDG, based on the loss of offsite power, during a loss of coolant accident (LOCA). The actual EDG Start has historically been associated with the SFAS actuation. The diesel loading has been included in the delay time associated with each safety system component requiring EDG supplied power following a loss of offsite power. This delay time includes contributions from the EDG Start, EDG loading, and safety injection system component actuation. The response of the EDG to a loss of power must be demonstrated to fall within this analysis response time when including the contributions of all portions of the delay.

The required channels of LOPS, in conjunction with the ESF systems powered from the EDGs, provide unit protection in the event of any of the analyzed accidents discussed in the accident analysis (Ref. 2), in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second EDG Start delay and, if applicable, the appropriate sequencing delay. The response times for SFAS actuated equipment in LCO 3.3.5, "Safety Features Actuation System (SFAS) Instrumentation," include the appropriate EDG loading and sequencing delay.

The EDG LOPS channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for the LOPS requires that two channels per bus of each LOPS instrumentation Function shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOPS supports safety systems associated with the SFAS. In MODES 5 and 6, the two channels per bus of each EDG LOPS instrument function, must be OPERABLE whenever the associated EDG is required to be OPERABLE to ensure that the automatic start of the EDG is available when needed. A channel is considered OPERABLE as long as one of the two undervoltage relays are OPERABLE.

BASES

LCO (continued)

Only Allowable Values are specified for each Function in the LCO. Nominal trip setpoints are specified in the unit specific setpoint calculations. The nominal setpoints are selected to ensure that the setpoint measured by CHANNEL FUNCTIONAL TESTS does not exceed the Allowable Value if the relay is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value specified is more conservative than the analytical limit assumed in the transient and accident analysis to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in the setpoint calculations.

Degraded Voltage LOPS

The minimum voltage (dropout) Allowable Value is the lowest voltage that results in all safety related loads having sufficient voltage to perform their safety related functions. With 4.16 kV essential bus voltages at the analytical limit of 3700 volts, all voltages are sufficient to meet this requirement. The Allowable Value includes channel uncertainty without including drift, calibration uncertainties, and uncertainties observed during normal operation.

The maximum voltage (pickup) Allowable Value corresponds to the lowest bus voltage that will ensure reset of the degraded voltage relays, as well as preclude unnecessary operation of the relays on a temporary voltage dip. The Allowable Value includes channel uncertainty without including drift, calibration uncertainties, and uncertainties observed during normal operation. An additional 3 Volts was subtracted from the Allowable Value for consistency with the Davis-Besse Nuclear Power Station AC Power Distribution analyses.

The minimum time delay Allowable Value is the bounding acceleration time for 4.16 kV motors expected to start due to a SFAS, based on the start time of the high pressure injection (HPI) pump motors at 70% of nominal voltage. The Allowable Value includes instrument channel uncertainty without including drift, and uncertainties observed during normal operation.

The maximum time delay Allowable Value is based on not exceeding the maximum EDG start time of 10 seconds. It includes a deduction to account for feeder breaker trip time, field collapse time, EDG breaker closure time, interposing relays, and uncertainties in the loss of voltage relays and dead bus timer settings, so that these delays, combined with

BASES

LCO (continued)

the delays from the degraded voltage relays and loss of voltage relays, do not exceed the maximum EDG start time. The Allowable Value includes instrument channel uncertainty without including drift, and uncertainties observed during normal operation.

Loss of Voltage LOPS

The minimum voltage (dropout) Allowable Value is based on ensuring that the relays will not actuate until below the lowest (worst case) bus voltage expected during the start of the large 4.16 kV motors and block loading of the SFAS loads while the offsite power sources are supplying power to the 4.16 kV essential buses.

The maximum voltage (pickup) Allowable Value is based on precluding an undesired interaction between the loss of voltage relays and the EDG loading sequence. The Allowable Value includes instrument channel uncertainty without including drift, calibration uncertainties, and uncertainties observed during normal operation.

The minimum time delay Allowable Value is based on preventing spurious trips due to transient events that may occur on the Offsite Transmission System or within the Onsite Electrical Distribution System. The Allowable Value includes instrument channel uncertainty without including drift, and uncertainties observed during normal operation.

The maximum time delay Allowable Value is based on providing for instrument uncertainty in maintaining the lower Allowable Value. The Allowable Value includes instrument channel uncertainty without including drift, and uncertainties observed during normal operation.

The Note allows all degraded voltage channels to be bypassed while starting a reactor coolant pump or circulating water pump. This prevents an actuation of the LOPS during the voltage decrease from the starting load of these pump motors. The one minute limit provides time for the starting current to decrease and bus voltage to return to normal.

APPLICABILITY

The EDG LOPS actuation Functions shall be OPERABLE in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation is also required whenever the EDG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown," so that the EDG can perform its function on a loss of power or degraded power to the essential bus.

ACTIONS

If a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that the channel provides must be declared inoperable and the LCO Condition

BASES

ACTIONS (continued)

entered for the particular protection function affected. Since the required channels are specified on a per bus basis, the Condition may be entered separately for each bus.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function.

A.1

If one channel per bus in one or more Functions is inoperable, it must be tripped within 1 hour. With a channel in trip, the EDG LOPS channels are configured to provide a one-out-of-one logic to generate an EDG LOPS signal. In trip, one additional valid actuation will cause an EDG LOPS signal on the bus. The 1 hour Completion Time is reasonable to evaluate and to take action by correcting a degraded condition in an orderly manner and takes into account the low probability of an event requiring an EDG LOPS occurring during this interval.

B.1

Condition B applies when two undervoltage or two degraded voltage channels per bus are inoperable.

Required Action B.1 requires one inoperable channel to be restored to OPERABLE status within 1 hour. With two channels as described above inoperable, the logic is not capable of providing an automatic EDG LOPS signal for valid loss of voltage or degraded voltage conditions. The 1 hour Completion Time is reasonable to evaluate and to take action by correcting the degraded condition in an orderly manner and takes into account the low probability of an event requiring an EDG LOPS occurring during this interval.

C.1

Condition C applies if the Required Action of Condition A or Condition B and the associated Completion Time is not met.

Required Action C.1 requires the associated EDG to be declared inoperable, which ensures that Required Actions for affected EDG inoperabilities are initiated. Depending on unit MODE, the Actions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, are required immediately.

BASES

SURVEILLANCE REQUIREMENTS

The Note to the Surveillance Requirements allows channel bypass for testing without entering the applicable Conditions and Required Actions even though the channel is inoperable during this time period and cannot actuate a diesel start. This allowance is based in the assumption that 2 hours is the average time required to perform channel Surveillance. The 2 hour testing allowance does not significantly reduce the probability that the EDG will start when necessary. It is not acceptable to routinely remove channels from service for more than 2 hours to perform required Surveillance testing.

SR 3.3.8.1

A CHANNEL FUNCTIONAL TEST is performed on each required EDG LOPS channel to ensure the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustments shall be consistent with the assumptions of the current unit specific setpoint calculations. As Noted, the as-left instrument setting shall be returned to a setting within the tolerance band of the trip setpoint established to protect the safety limit. The Frequency of 31 days is considered reasonable based on the reliability of the components and on operating experience that demonstrates channel failure is rare.

SR 3.3.8.2

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The setpoints and the response to a loss of voltage and a degraded voltage test shall include a single point verification that the trip occurs within the required delay time. CHANNEL CALIBRATION shall find that measurement setpoint errors are within the assumptions of the unit specific setpoint calculations. As Noted, the as-left instrument setting shall be returned to a setting within the tolerance band of the trip setpoint established to protect the safety limit.

The Frequency is based on operating experience and is justified by the assumption of a 12 month calibration interval in the determination of equipment drift in the setpoint calculation.

BASES

REFERENCES

1. UFSAR, Section 8.3.1.1.
2. UFSAR, Section 6.3.
3. IEEE-279-1971.

B 3.3 INSTRUMENTATION

B 3.3.9 Source Range Neutron Flux

BASES

BACKGROUND

The Reactor Protection System (RPS) source range neutron flux channels provide the operator with an indication of the approach to criticality at lower power levels than can be seen on the intermediate range neutron flux instrumentation. These channels also provide the operator with a flux indication that reveals changes in reactivity and helps to verify that SDM is being maintained.

The source range instrumentation has two redundant count rate channels originating in two high sensitivity proportional counters. Two source range detectors are externally located on opposite sides of the core 180°. These channels are used over a counting range of 0.1 cps to 1E6 cps and are displayed on the operator's control console in terms of log count rate. The channels also measure the rate of change of the neutron flux level, which is displayed for the operator in terms of startup rate from -0.5 decades to +5 decades per minute. An interlock provides a control rod withdraw "inhibit" on a high startup rate of +2 decades per minute in either channel.

The proportional counters of the source range channels are BF_3 chambers. The detector high voltage is automatically turned off when the flux level is approximately one decade above the useful operating range. Conversely, the high voltage is turned on automatically when the flux level returns to within approximately one decade of the detectors' maximum useful range. High voltage will be turned off automatically when the flux level is above 1E-9 amp in both intermediate range channels, or 10% power in power range channels (i.e., NI-5 or NI-6 and NI-7 or NI-8).

APPLICABLE SAFETY ANALYSES

The source range neutron flux channels are necessary to monitor core reactivity changes. It is the primary means for detecting and triggering operator actions to respond to reactivity transients initiated from conditions in which the Reactor Protection System (RPS) is not required to be OPERABLE. It also triggers operator actions to anticipate RPS actuation in the event of reactivity transients during startup and shutdown conditions. However, the source range neutron flux channels are not credited in the safety analysis.

The source range neutron flux channels have no safety function and are not assumed to function during any UFSAR design basis accident or transient analysis. However, the source range neutron flux channels provide on scale monitoring of neutron flux levels during startup and shutdown conditions. Therefore, they are being retained in Technical Specifications.

BASES

LCO

Two source range neutron flux channels (i.e., the channels associated with the RPS) shall be OPERABLE whenever the control rods are capable of being withdrawn to provide the operator with redundant source range neutron instrumentation. The source range instrumentation is the primary power indication at low power levels ≤ 1E-10 amp on intermediate range instrumentation and must remain OPERABLE for the operator to continue increasing power.

A Note has been added allowing detector high voltage to be de-energized with neutron flux > 1E-10 amp on the intermediate range channels. Above this point, the source range instrumentation is no longer the primary power indicator. As such, the high voltage to the source range detectors may be de-energized.

APPLICABILITY

Two source range neutron flux channels shall be OPERABLE in MODE 2 to provide redundant indication during an approach to criticality. Neutron flux level is sufficient for monitoring on the intermediate range and on the power range instrumentation prior to entering MODE 1; therefore, source range instrumentation is not required in MODE 1.

In MODES 3, 4, and 5, source range neutron flux instrumentation shall be OPERABLE to provide the operator with a means of monitoring changes in SDM and to provide an early indication of reactivity changes.

The requirements for source range neutron flux instrumentation during MODE 6 refueling operations are addressed in LCO 3.9.2, "Nuclear Instrumentation."

ACTIONS

A.1

The Required Action for one channel of the source range neutron flux indication inoperable with neutron flux ≤ 1E-10 amp on the intermediate range neutron flux instrumentation is to delay increasing reactor power until the channel is repaired and restored to OPERABLE status. This limits power increases in the range where the operators rely solely on the source range instrumentation for power indication. The Completion Time ensures the source range is available prior to further power increases.

B.1, B.2, B.3, and B.4

With both source range neutron flux channels inoperable with neutron flux ≤ 1E-10 amp on the intermediate range neutron flux instrumentation, the operators must take actions to limit the possibilities for adding positive reactivity and to verify adequate SDM. This is done by immediately suspending positive reactivity additions, initiating action to insert all

BASES

ACTIONS

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

CONTROL RODS, and opening the CONTROL ROD drive trip breakers and verifying SDM is within limit within 1 hour. Periodic SDM verification is then required to provide a means for detecting the slow reactivity changes that could be caused by mechanisms other than control rod withdrawal or operations involving positive reactivity changes. Since the source range instrumentation provides the only reliable direct indication of power in this condition, the operators must continue to verify the SDM every 12 hours until at least one channel of the source range instrumentation is returned to OPERABLE status. Required Action B.1, Required Action B.2, and Required Action B.3 preclude rapid positive reactivity additions. The 1 hour Completion Time for Required Action B.3 and Required Action B.4 provides sufficient time for operators to accomplish the actions. The 12 hour Frequency for performing the SDM verification ensures that the reactivity changes possible with CONTROL RODS inserted are detected before SDM limits are challenged.

Required Action B.1 is modified by a Note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM.

C.1

With neutron flux > 1E-10 amp on the intermediate range neutron flux instrumentation, continued operation is allowed with one or more source range neutron flux channels inoperable. The ability to continue operation is justified because the instrumentation does not provide a safety function during high power operation. However, actions are initiated within 1 hour to restore the channel(s) to OPERABLE status for future availability. The Completion Time of 1 hour is sufficient to initiate the action. The action must continue until channels are restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1 (continued)

CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels. When operating in Required Action A.1, CHANNEL CHECK is still required. However, in this condition, a redundant source range is not available for comparison. CHANNEL CHECK may still be performed via comparison with Post Accident Monitoring source range detectors, if available, and verification that the OPERABLE source range channel is energized and indicating a value consistent with current unit status.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.2

For source range neutron flux channels, CHANNEL CALIBRATION is a complete check and readjustment of the channels from the preamplifier input to the indicators. This test verifies the channel responds to measured parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests.

The SR is modified by a Note excluding neutron detectors from CHANNEL CALIBRATION. It is not necessary to test the detectors because generating a meaningful test signal is difficult. The detectors are of simple construction, and any failures in the detectors will be apparent as a change in channel output.

The Frequency of 18 months is based on demonstrated instrument CHANNEL CALIBRATION reliability over an 18 month interval, such that the instrument is not adversely affected by drift.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.10 Intermediate Range Neutron Flux

BASES

BACKGROUND	The intermediate range neutron flux channels provide the operator with an indication of reactor power at higher power levels than the source range instrumentation and lower power levels than the power range instrumentation. The intermediate range instrumentation has two log NI channels originating in two electrically identical gamma compensated ion chambers. Each channel provides eight decades of flux level information in terms of the log of ion chamber current from 1E-11 amp to 1E-3 amp. The channels also measure the rate of change of the neutron flux level, which is displayed for the operator in terms of startup rate from -0.5 decades to +5 decades per minute. A high startup rate of +3 decades per minute in either channel will initiate a control rod withdrawal inhibit. The intermediate range compensated ion chambers are of the electrically adjustable gamma compensating type. Each detector has a separate adjustable high voltage power supply and an adjustable compensating voltage supply.
APPLICABLE SAFETY ANALYSES	Intermediate range neutron flux channels are necessary to monitor core reactivity changes and are the primary indication to trigger operator actions to anticipate Reactor Protection System (RPS) actuation in the event of reactivity transients starting from low power conditions. However, the intermediate range neutron flux channels are not credited in the safety analysis. The intermediate range neutron flux channels have no safety function and are not assumed to function during any UFSAR design basis accident or transient analysis. However, the intermediate range neutron flux channels provide on scale monitoring of neutron flux levels during startup and shutdown conditions. Therefore, they are being retained in Technical Specifications.
LCO	Two intermediate range neutron flux instrumentation channels shall be OPERABLE to provide the operator with redundant neutron flux indication. These enable operators to control the increase in power and to detect neutron flux transients. This indication is used until the power range instrumentation is on scale. Violation of this requirement could prevent the operator from detecting and controlling neutron flux transients that could result in reactor trip during power escalation.

BASES

APPLICABILITY

The intermediate range neutron flux channels shall be OPERABLE in MODE 2 and in MODES 3, 4 and 5 with any CONTROL ROD drive (CRD) trip breaker in the closed position and the CRD System capable of rod withdrawal.

The intermediate range instrumentation is designed to detect power changes during initial criticality and power escalation when the power range and source range instrumentation cannot provide reliable indications. Since those conditions can exist in all of these MODES, the intermediate range instrumentation must be OPERABLE.

ACTIONS

A.1

If one intermediate range channel becomes inoperable when the channels indicate > 1E-10 amp, the unit is exposed to the possibility that a single failure will disable all RPS neutron monitoring instrumentation. To avoid this, the inoperable channel must be repaired or power must be reduced to the point where source range channels can provide neutron flux indication. Completion of Required Action A.1 places the unit in this state, and LCO 3.3.9, "Source Range Neutron Flux," requires OPERABILITY of two source range detectors once this state is reached. If the one channel failure occurs when indicated power is ≤ 1E-10 amp, the Required Action prohibits increases in power above the source range capability.

The 2 hour Completion Time allows controlled reduction of power into the source range and is based on unit operating experience that demonstrates the improbability of the second intermediate range channel failing during the allowed interval.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met or with two intermediate range neutron flux channels inoperable, the operators must place the reactor in the next lowest condition for which the intermediate range instrumentation is not required. This involves providing power level indication on the source range instrumentation by immediately suspending operations involving positive reactivity changes and, within 1 hour, placing the reactor in the tripped condition with the CRD trip breakers open. The Completion Times are based on unit operating experience and allow the operators sufficient time to manually insert the CONTROL RODS prior to opening the CRD breakers.

BASES

ACTIONS

B.1 and B.2 (continued)

Required Action B.1 is modified by a Note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM.

SURVEILLANCE REQUIREMENTS

SR 3.3.10.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels.

When operating in Required Action A.1, CHANNEL CHECK is still required. However, in this condition, a redundant intermediate range is not available for comparison. CHANNEL CHECK may still be performed via comparison with power or source range detectors, if available, and verification that the OPERABLE intermediate range channel is energized and indicates a value consistent with current unit status.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.10.2

For intermediate range neutron flux channels, CHANNEL CALIBRATION is a complete check and readjustment of the channels, from the RPS cabinet input to the indicators. This test verifies the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests.

The SR is modified by a Note excluding neutron detectors from CHANNEL CALIBRATION. It is not necessary to test the detectors because generating a meaningful test signal is difficult. In addition, the detectors are of simple construction, and any failures in the detectors will be apparent as a change in channel output. The Frequency is based on operating experience and consistency with the typical industry refueling cycle and is justified by demonstrated instrument reliability over an 18 month interval such that the instrument is not adversely affected by drift.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.11 Steam and Feedwater Rupture Control System (SFRCS) Instrumentation

BASES

BACKGROUND

The SFRCS is designed to automatically start the Auxiliary Feedwater (AFW) System in the event of a main steam line break (MSLB), main feedwater (MFW) line rupture, a low level in the steam generators or a loss of all four reactor coolant pumps. SFRCS is designed to automatically isolate the Main Steam System and MFW System in the event of a MSLB or MFW line rupture. The AFW System is automatically aligned to feed the unaffected steam generator (SG) upon a loss of steam pressure in one of the SGs.

The SFRCS is required to ensure an adequate feedwater supply to remove reactor decay heat during periods when the normal feedwater supply has been lost.

The SFRCS instrumentation provides input to the logic from the following inputs:

1. Main Steam Line Pressure - Low;

2. Feedwater/Steam Generator Differential Pressure - High;

3. Steam Generator Level - Low; and

4. Loss of RCPs.

AFW is initiated to restore a source of cooling water to the SGs when conditions indicate that the normal source of feedwater is insufficient to meet heat removal requirements. A high Feedwater/SG Differential Pressure and a low level in the steam generator indicate a loss of MFW. AFW is initiated and SGs are isolated upon detection of a rupture of a main steam line or MFW line which is sensed when steam pressure reaches the low main steam line pressure setpoint or the differential pressure between the feedwater and SG reaches the high level setpoint, respectively. On the loss of all reactor coolant pumps (RCPs) the primary system experiences a total loss of forced circulation, AFW is initiated to to promote natural circulation cooling.

The SFRCS will isolate main steam and MFW to an SG upon a loss of pressure control. A loss of pressure control in an SG identifies that heat sink temperature control is lost and the heat removal rate cannot be controlled. SFRCS automatically aligns the AFW System to the

BACKGROUND (continued)

unaffected SG to avoid uncontrolled heat removal rates from the affected SG. Under other conditions (i.e., Feedwater/SG Differential Pressure - High, SG Level - Low, and Loss of RCPs), SFCRS will align both main steam lines to each AFW pump turbine and align each AFW train to discharge to its associated SG.

Figure 7.4-4, UFSAR Section 7.4.1.3 (Ref. 1), illustrates SFRCS logic operation. The SFRCS consists of two independent and redundant actuation channels. Each actuation channel consists of two electrically independent complementary logic channels. Each complementary logic channel contains identical sets of SFRCS instrumentation for monitoring key parameters and issuing trip signals when a limiting condition has been reached within the actuation channel. The trip output of each complementary logic channel is combined in each actuation channel in a two-out-of-two logic, so that SFRCS will initiate an actuation channel trip when both of the complementary logic channels trip. The logic channel trip will result in de-energization of the SFRCS output relays contained within the actuation channel. Making the actual trip logic of each of the two redundant SFRCS actuation channels a two-out-of-two logic.

1. Main Steam Line Pressure - Low

   Main Steam Line Pressure - Low is monitored by four pressure switches on each main steam line. Two pressure switches, one from each main steam line, provides input into each logic channel. The associated SFRCS actuation channel initiates a trip signal when both pressure switches associated with a main steam line actuate, one in each of the logic channels. The low pressure Function may be manually bypassed when both steam lines are less than 750 psig to accommodate normal shutdown of the facility without an SFRCS actuation. If either steam line exceeds 800 psig, the SFRCS channel bypass will be automatically removed.

   The following instruments supply the input signals for the Main Steam Line Pressure - Low Function:

   PS 3689B Steam Line 1 logic channel 1;
   PS 3689D Steam Line 2 logic channel 1;
   PS 3689F Steam Line 1 logic channel 3;
   PS 3689H Steam Line 2 logic channel 3;
   PS 3687A Steam Line 2 logic channel 2;
   PS 3687C Steam Line 1 logic channel 2;
   PS 3687E Steam Line 2 logic channel 4; and
   PS 3687G Steam Line 1 logic channel 4.

BACKGROUND (continued)

Main Steam Line Pressure - Low is a primary indication and actuation signal for MSLB or MFW line break (MFWLB) downstream of the first check valve located upstream of the main feedwater stop valve (MFSV). For small breaks, which do not depressurize the SG or take a long time to depressurize, automatic actuation is not required. The operator has time to diagnose the problem and take appropriate actions.

2. Feedwater/Steam Generator Differential Pressure - High

Feedwater/SG Differential Pressure - High is monitored by four differential pressure switches that sense the differential pressure across a check valve located on each MFW line. Each logic channel within an actuation channels contains two differential pressure switches, one from each MFW line. The associated SFRCS actuation channel will initiate a signal when two differential pressure switches associated with either feedwater line actuate, one in each of the logic channels. Feedwater/SG Differential Pressure is the primary indication for rapid pressure transients resulting from a MFWLB upstream of the first check valve located upstream of the MFSV. A Feedwater/SG Differential Pressure trip can actuate upon a loss of MFW pumps.

The following instruments supply the input signals for the Feedwater/ Steam Generator Differential Pressure - High Function:

PDS 2685A Feedwater/Steam Generator 2 logic channel 2;
PDS 2685B Feedwater/Steam Generator 2 logic channel 4;
PDS 2685C Feedwater/Steam Generator 2 logic channel 1;
PDS 2685D Feedwater/Steam Generator 2 logic channel 3;
PDS 2686A Feedwater/Steam Generator 1 logic channel 1;
PDS 2686B Feedwater/Steam Generator 1 logic channel 3;
PDS 2686C Feedwater/Steam Generator 1 logic channel 2; and
PDS 2686D Feedwater/Steam Generator 1 logic channel 4.

3. Steam Generator Level - Low

Steam Generator Level - Low is monitored by four dedicated startup range level transmitters per SG which are used to generate the signals for detection of low level conditions within each SG. Two transmitters provide an input into each logic channel, one from each SG. The associated SFRCS actuation channel will initiate a trip when two transmitters associated with the same SG sense a low level condition. The SG startup level is measured from 0 inches to 300 inches.

BACKGROUND (continued)

Steam Generator Level - Low indicates that the primary feedwater source is insufficient to meet the heat removal requirements and, therefore, additional cooling water is necessary to ensure core decay heat removal.

The Steam Generator Level - Low is a backup to the Main Steam Line Pressure - Low trip and the Feedwater/Steam Generator Differential Pressure - High trip.

The following instruments supply the input signals for the Steam Generator Level - Low Function:

LSLL SP9B8 Steam Generator 1 logic channel 1;
LSLL SP9B9 Steam Generator 1 logic channel 3;
LSLL SP9A6 Steam Generator 2 logic channel 1;
LSLL SP9A7 Steam Generator 2 logic channel 3;
LSLL SP9A8 Steam Generator 2 logic channel 2;
LSLL SP9A9 Steam Generator 2 logic channel 4;
LSLL SP9B6 Steam Generator 1 logic channel 2; and
LSLL SP9B7 Steam Generator 1 logic channel 4.

4. Loss of RCPs

A loss of all four RCPs is an indication of a loss of forced flow in the Reactor Coolant System (RCS). Each RCP motor has four RCP current monitoring circuits. A current transformer on one phase of each RCP motor provides current signals to four current monitoring circuits. Each circuit is able to detect an RCP motor overcurrent condition, an overloaded or binding shaft, or an RCP motor undercurrent condition, sheared shaft. Each SFRCS logic channel receives an input from the RCP current monitoring circuit. The SFRCS associated actuation channel will initiate a trip when both logic channels receive input of an overcurrent or an undercurrent condition on all RCP motors.

All SFRCS functions will align AFW discharge valves and Main Steam valves concurrent with AFW initiation. The SFRCS logic aligns the AFW discharge valves and main steam valves to provide AFW to each SG and both main steam lines to each AFW turbine for a Feedwater/SG Differential Pressure - High trip, a SG Level - Low trip, or a Loss of RCPs trip. The signals provided to the AFW and Main Steam valves are consistent with the normal position of the valves except for the AFW Steam Admission valves and two Main Steam valves. The main steam valves that are repositioned do not prevent actuation of the AFW System if they fail to reposition.

BACKGROUND (continued)

For Main Steam Line Pressure - Low, the AFW discharge valves and main steam valves receive different open or close signals depending on the steam line affected. Upon a low pressure in main steam line 1, the two actuation channels will align both AFW pumps to provide feedwater to SG 2 and align the main steam supply of both AFW pump turbines to come from SG 2. SFRCS actuation channel 1 will close AFW pump 1 discharge valve to SG 1, open AFW pump 1 discharge valve to SG 2, close AFW pump turbine 1 main steam supply from SG 1 and open AFW pump turbine 1 main steam supply from SG 2. SFRCS actuation channel 2 will close AFW pump 2 discharge valve to SG 1, open AFW pump 2 discharge valve to SG 2, close AFW pump turbine 2 main steam supply from SG 1 and open AFW pump turbine 2 main steam supply from SG 2. Upon a low pressure in main steam line 2, the two actuation channels will align both AFW pumps to provide feedwater to SG 1 and align the main steam supply of both AFW pump turbines to come from SG 1. SFRCS actuation channel 1 will open AFW pump 1 discharge valve to SG 1, close AFW pump 1 discharge valve to SG 2, open AFW pump turbine 1 main steam supply from SG 1 and close AFW pump turbine 1 main steam supply from SG 2. SFRCS actuation channel 2 will open AFW pump 2 discharge valve to SG 1, close AFW pump 2 discharge valve to SG 2, open AFW pump turbine 2 main steam supply from SG 1 and close AFW pump turbine 2 main steam supply from SG 2.

Main Steam line and MFW isolation is provided by the Main Steam Line Pressure - Low trip and the Feedwater/SG Differential Pressure - High trip. Once isolation of the SGs has occurred, manual action is required to defeat the isolation command as desired.

The Main Steam Line Isolation Function is accomplished by closing the main steam isolation valves (MSIVs) and the turbine stop valves (TSVs). The TSVs serve as a backup to the MSIVs.

The MFW Isolation Function limits the overcooling of the RCS following a MSLB or MFWLB. The isolation function limits the mass and energy released to containment following a MSLB or MFWLB. The function is accomplished by closing the MFSVs, the main feedwater control valves (MFCVs), and the startup feedwater control valves (SFCVs).

Trip Setpoints and Allowable Values

The trip setpoints are the nominal value at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.

BACKGROUND (continued)

The trip setpoints used in the bistables are based on the analytical limits. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing uncertainties are taken into account. The Allowable Values specified in Table 3.3.11-1 are conservatively adjusted with respect to the analytical limits to allow for calibration tolerances, instrumentation uncertainties, and instrument drift that is not present or not measured during CHANNEL FUNCTIONAL TESTS, and severe environmental errors for those SFRCS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 2). The trip setpoint is established using Method 1 or Method 2 of Reference 3 or 4. The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION. One example of such a change in measurement error is drift during the surveillance interval. A channel is inoperable if its actuation trip setpoint is not within its required Allowable Value.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) are acceptable, providing the unit is operated from within the LCOs at the onset of the DBA, and that the equipment functions as designed.

Each channel can be tested on line to verify that the setpoint accuracy is within the specified allowance requirements of UFSAR, Table 7.4-1 (Ref. 5). Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. The SRs for the channels are specified in the SR Section.

The Allowable Values listed in Table 3.3.11-1 are established using Method 1 or 2 of Reference 3 or 4, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each trip setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

APPLICABLE SAFETY ANALYSES

The MFW line break analysis assumes the Feedwater/Steam Generator Differential Pressure - High trip isolates the unaffected steam generator from the line break thus assuring adequate inventory and pressure to run the available AFW pump turbines. The analysis further assumes that the Main Steam Line Pressure - Low trip realigns the AFW System to take steam from and to feed the unaffected steam generator.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSLB analysis assumes the Main Steam Line Pressure - Low trip isolates the unaffected steam generator from the line break thus assuring adequate inventory and pressure to run the available AFW pump turbines. The analysis further assumes that the Main Steam Line Pressure - Low trip realigns the AFW System to take steam from and to feed the unaffected steam generator.

The Main Steam Isolation Function is accomplished by closing the MSIVs and the TSVs. While the TSVs serve as a backup to the MSIVs, closure of the TSVs ensures that both steam generators do not blowdown following a MSLB in conjunction with a failure of the unaffected steam generator's associated MSIV failing to close.

The Main Feedwater Isolation Function is accomplished by closing the MFSVs, the MFCVs, and the SFCVs.

The Loss of Feedwater (LOFW) analysis assumes the Steam Generator Level - Low trip initiates the AFW System.

The SFRCS System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

All instrumentation performing an SFRCS System Function in Table 3.3.11-1 shall be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

Four channels are required OPERABLE for all SFRCS instrumentation Functions as specified in Table 3.3.11-1 to ensure that no single failure prevents actuation of a train. Each SFRCS instrumentation channel is considered to include the sensors and measurement channels for each Function, the operational bypass switches, and permissives. Failures that disable the capability to place a channel in operational bypass, but which do not disable the trip Function, do not render the protection channel inoperable.

Only the Allowable Values are specified for each SFRCS initiation and bypass removal function in the LCO. In Table 3.3.11-1, Allowable Values for the bypass removal functions are specified in terms of applicability limits on the associated trip Function. Nominal trip setpoints are specified in the unit specific setpoint calculations. However, for Functions 1, 2, and 3, the Limiting Trip Setpoint and methodology used to determine the Limiting Trip Setpoint, the predefined as-found acceptance criteria, and the as-left tolerance are also specified in the Technical Requirements Manual (TRM) (Ref. 6). In no case shall the predefined as-found acceptance criteria band overlap the Allowable Value. If one end of the predefined as-found acceptance criteria band is truncated due to its

LCO (continued)

proximity to the Allowable Value, this does not affect the other end of the predefined as-found acceptance criteria band. If equipment is replaced, such that the previous as-left value is not applicable to the current configuration, the as-found acceptance criteria band is not applicable to calibration activities performed immediately following the equipment replacement. The nominal setpoints are selected to ensure the setpoints measured by CHANNEL FUNCTIONAL TESTS do not exceed the Allowable Value if the bistable is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable provided that operation and testing are consistent with the assumptions of the unit specific setpoint calculations. Each Allowable Value specified is more conservative than the analytical limit assumed in the safety analysis to account for instrument uncertainties appropriate to the trip Function. These uncertainties are defined in the setpoint calculations.

The Bases for the LCO requirements of each specific SFRCS Function are discussed next.

1. Main Steam Line Pressure - Low

   Four SFRCS channels per main steam line shall be OPERABLE with main steam line low pressure actuation setpoints set consistent with the Allowable Value. The setpoint is chosen to avoid actuation under transient conditions not requiring secondary system isolation, preferring to maintain a steaming path to the condenser, if possible. The Main Steam Line Pressure - Low Function includes a bypass enable and removal function. The bypass enable and removal values (< 750 psig during a shutdown and ≤ 800 psig during a heatup) are chosen to allow sufficient operating margin for the operator to bypass when cooling down.

2. Feedwater/Steam Generator Differential Pressure - High

   Four SFRCS channels per feedwater line shall be OPERABLE with setpoints set consistent with the Allowable Value. The Allowable Value was chosen as a good indication of MFWLB.

3. Steam Generator Level - Low

   Four SFRCS dedicated startup range level transmitters per SG shall be OPERABLE with Steam Generator Level - Low actuation setpoints set consistent with the Allowable Value. The Allowable Value of 17.3 inches was based on actual water level above the lower steam generator tube sheet in the original steam generators. This corresponded to an approximate indicated level of 23 inches.

BASES

LCO (continued)

The tube sheets in the replacement steam generators are thinner, resulting in the secondary side face of the tube sheet being approximately 2 inches lower. The level sensing connections in the replacement steam generators are at the same elevation as in the original steam generators. Therefore, at an indicated level of 23 inches, there will be approximately 2 inches of additional water level above the lower tube sheet in the replacement steam generators. Based on this, maintaining the original level setpoint for the replacement steam generators is conservative because it will result in an additional water level of approximately 2 inches above the lower tube sheet when the low level trip setpoint is reached. This provides additional margin for decay heat removal. Operation of the Steam Generators on low level limit control at an indicated level of 40 inches is sufficiently above the Allowable Value.

4. Loss of RCPs

Four SFRCS channels (with each channel receiving input from an RCP monitoring circuit monitoring the current on each RCP motor) for RCP status shall be OPERABLE. This ensures that upon the loss of four RCPs, AFW will be automatically initiated. The Allowable Values are selected to detect an RCP motor overcurrent condition, as would be found with an overloaded or binding shaft, and an RCP motor undercurrent condition, as would be found with a sheared shaft.

APPLICABILITY

The SFRCS System instrumentation Functions shall be OPERABLE in accordance with Table 3.3.11-1. Each Function has its own requirements that are based on the specific accidents and conditions that it is designed to protect against.

The Feedwater/Steam Generator Differential Pressure - High shall only be required in MODES 1, 2, and 3, when core power production and heat removal requirements are the greatest. Below these unit conditions, the energy level is low and the secondary side feedwater flow is low or nonexistent.

Steam Generator Level - Low Function shall be OPERABLE at all times the SG is required for heat removal. These conditions include MODES 1, 2, and 3. To avoid automatic actuation of the AFW pumps during normal heatup and cooldown transients, the low SG level Function is not required to be OPERABLE in MODES 4, 5, and 6.

The Loss of RCPs Function shall be OPERABLE in MODES 1, 2, and 3 when the RCPs are required to be in operation.

BASES

APPLICABILITY (continued)

The Main Steam Line Pressure - Low shall be OPERABLE in MODES 1, 2, and 3 with main steam line pressure ≥ 750 psig during a shutdown and > 800 psig during a heatup because the SG inventory can be at a high energy level and contribute significantly to the peak pressure with a secondary side break. Both the normal feedwater and the AFW must be able to be isolated on each SG to limit overcooling of the primary and mass and energy releases to the containment. Once the main steam line pressures have decreased below 750 psig, the Main Steam Line Pressure - Low Function can be manually bypassed to avoid actuation during normal unit cooldowns. On a unit heatup, the Main Steam Line Pressure - Low Function bypass is automatically removed prior to exceeding 800 psig. In MODES 4, 5, and 6, the energy level is low and the secondary side feedwater flow rate is low or nonexistent. In MODES 4, 5, and 6, SFRCS instrumentation is not required to be OPERABLE.

BASES

ACTIONS

If a channel's trip setpoint is found non-conservative with respect to the Allowable Value in Table 3.3.11-1, or any transmitter, signal processing electronics, or SFRCS channel cabinet modules are found inoperable, then the channel must be declared inoperable and the applicable Condition must be entered immediately.

A Note has been added to the ACTIONS indicating that a separate Condition entry is allowed for each Function.

A.1

Condition A applies to inoperabilities of a single instrumentation channel for one or more Functions.

With one channel inoperable in one or more Functions listed in Table 3.3.11-1, the channel(s) must be placed in trip within 1 hour. With the channel in trip, the resultant logic in the affected actuation channel is one-out-of-one. The Completion Time of 1 hour is adequate to perform Required Action A.1.

BASES

ACTIONS (continued)

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

If the Required Actions cannot be met within the required Completion Time or if one or more Functions have two or more channels inoperable, the unit must be placed in a MODE or condition in which the requirement does not apply. This is done by placing the unit in a nonapplicable MODE for the particular Function. The nonapplicable MODE for all Functions except Main Steam Line Pressure - Low is MODE 4 and for Main Steam Line Pressure - Low Function is MODE 3 with main steam line pressure less than 750 psig. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

A Note indicates that the SRs for each SFRCS instrumentation Function are identified in the SRs column of Table 3.3.11-1. SFRCS Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, CHANNEL CALIBRATION and SFRCS RESPONSE TIME.

SR 3.3.11.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the transmitter or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

SURVEILLANCE
REQUIREMENTS (continued)

SR 3.3.11.1 (continued)

The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel operability during normal operational use of the displays associated with the LCO required channels.

SR 3.3.11.2

A CHANNEL FUNCTIONAL TEST verifies the function of the required trip, interlock, and alarm functions of the channel. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Setpoints for both trip and bypass removal functions must be found within the Allowable Value specified in the LCO. (Note that the Allowable Values for the bypass removal functions are specified in the Applicable MODES or Other Specified Condition column of Table 3.3.11-1 as limits on applicability for the trip Functions.) Any setpoint adjustment shall be consistent with the assumptions of the current unit specific setpoint analysis. The CHANNEL FUNCTIONAL TEST of the Main Steam Line Pressure - Low instrumentation includes the logic for the main steam line pressure shutdown bypasses.

The Frequency of 31 days is based on unit operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is a rare event.

This SR is modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of the CHANNEL FUNCTIONAL TEST, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the channels providing input to the other actuation channel are OPERABLE. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This is acceptable since the channels providing input to the other actuation channel will continue to ensure the associated SFRCS Function can perform its assumed function.

SURVEILLANCE REQUIREMENTS

SR 3.3.11.2 (continued)

SR 3.3.11.2 for Functions 1, 2, and 3 are modified by two Notes as identified in Table 3.3.11-1. These Functions are an LSSS for protection system instrument channels that protect reactor core or RCS pressure boundary Safety Limits. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. For digital channel components, the as-found tolerance may be identical to the as-left tolerance since drift may not be an expected error. In these cases, a channel as-found value outside the as-left condition may be cause for component assessment. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance around the Limiting Trip Setting (LTSP), or a value that is more conservative than the LTSP. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance or a setting more conservative than the LTSP, then the instrument channel shall be declared inoperable. The second Note also requires that the LTSP and the methodology used to determine the LTSP, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in the TRM (Ref. 6).

SR 3.3.11.3 and SR 3.3.11.4

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The test verifies the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channels adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the unit specific setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint analysis. The CHANNEL CALIBRATION of the Main Steam Line Pressure - Low instrumentation includes the main steam line pressure shutdown bypass function.

SURVEILLANCE REQUIREMENTS

SR 3.3.11.3 and SR 3.3.11.4 (continued)

The Frequency for SR 3.3.11.3 is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency for SR 3.3.11.4 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.11.3 for Functions 1 and 2 and SR 3.3.11.4 for Function 3 are modified by two Notes as identified in Table 3.3.11-1. These Functions are an LSSS for protection system instrument channels that protect reactor core or RCS pressure boundary Safety Limits. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. For digital channel components, the as-found tolerance may be identical to the as-left tolerance since drift may not be an expected error. In these cases, a channel as-found value outside the as-left condition may be cause for component assessment. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance around the LTSP, or a value that is more conservative than the LTSP. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance or a setting more conservative than the LTSP, then the instrument channel shall be declared inoperable. The second Note also requires that the LTSP and the methodology used to determine the LTSP, the predefined as-found acceptance criteria band, and the as-left setpoint tolerance band are specified in the TRM (Ref. 6).

SR 3.3.11.5

This SR verifies individual channel actuation response times are less than or equal to the maximum value assumed in the accident analysis.

Individual component response times are not modeled in the analysis. The analysis models the overall or total elapsed time, from the point at which the parameter exceeds the actuation setpoint value at the sensor, to the point at which the end device is actuated. Thus, this SR

SURVEILLANCE REQUIREMENTS

SR 3.3.11.5 (continued)

encompasses the automatic actuation logic components covered by LCO 3.3.13, "Steam and Feedwater Rupture Control System (SFRCS) Actuation," and the operation of the mechanical components (i.e., auxiliary feedwater pumps, main steam isolation valves, main feedwater valves, and turbine stop valves). Response time testing acceptance criteria are included in the TRM (Ref. 6).

SFRCS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. SFRCS RESPONSE TIME testing includes the AFW pumps for Functions 1, 2, 3, and 4, the MSIVs for Functions 1 and 2, the main feedwater isolation valves (MFCVs, SFCVs, and MFSVs) for Functions 1 and 2, and the TSVs for Function 1. Testing of the final actuation devices, which make up the bulk of the SFRCS RESPONSE TIME, is included in the testing of each channel. Therefore, staggered testing results in response time verification of these devices every 24 months. A Note requires STAGGERED TEST BASIS Frequency to be determined based on two channels per Function, in lieu of the eight total channels per Function for Functions 1, 2, and 3 and the four total channels for Function 4 specified in Table 3.3.11-1. This Frequency is based on the logic interrelationships of the various channels required to produce an SFRCS actuation. The two channels identified in the Note correspond to the two SFRCS actuation channels for each Function. The 24 month test Frequency is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. UFSAR, Section 7.4.1.3, Figure 7.4-4.
2. 10 CFR 50.49.
3. ISA RP 67.04 Part II 1994, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."
4. ISA RP 67.04.02-2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."
5. UFSAR, Table 7.4-1.
6. Technical Requirements Manual (TRM).

B 3.3 INSTRUMENTATION

B 3.3.12 Steam and Feedwater Rupture Control System (SFRCS) Manual Initiation

BASES

BACKGROUND

The SFRCS manual initiation capability provides the operator with the capability to actuate SFRCS Functions from the control room in the absence of any other initiation condition. Manually actuated Functions include Auxiliary Feedwater Pump Turbine (AFPT) 1 Initiation; AFPT 2 Initiation; AFPT 1 Initiation and Steam Generator (SG) 1 Isolation; and AFPT 2 Initiation and SG 2 Isolation.

Depressing switch HIS-6401 will start the AFPT 1. Main steam to AFPT 1 and feedwater from auxiliary feedwater pump (AFP) 1 will be lined up with SG 1. The cross connection of the auxiliary feedwater to SG 2 will be closed, while the cross connection of the main steam from SG 2 will remain as is; that means for normal system line-up, both steam generators will feed AFPT 1. Further, Anticipatory Reactor Trip System (ARTS) and the Main Turbine will be tripped.

Depressing switch HIS-6402 will start the AFPT 2. Main steam to AFPT 2 and feedwater from AFP 2 will be lined up with SG 2. The cross connection of the auxiliary feedwater to SG 1 will be closed, while the cross connection of the main steam from SG 1 will remain as is; that means for normal system line-up, both steam generators will feed AFPT 2. Further, ARTS and the Main Turbine will be tripped.

Depressing switch HIS-6403 will start AFPT 1. Main steam to AFPT 1 and feedwater from AFP 1 will be lined up with SG 1. The cross connection of the auxiliary feedwater to SG 2 will be closed, while the cross connection of the main steam from SG 2 will remain as is; that means for normal system line-up, both steam generators will feed AFPT 1. All SFRCS isolation valves of SG 1 from actuation channel 1 will be closed, including the main steam isolation valve (MSIV), the main steam warm-up isolation valve and the main feedwater isolation valves (MFIVs).

Depressing switch HIS-6404 will start AFPT 2. Main steam to AFPT 2 and feedwater from AFP 2 will be lined up with SG 2. The cross connection of the auxiliary feedwater to SG 1 will be closed, while the cross connection of the main steam from SG 1 will remain as is; that means for normal system line-up, both steam generators will feed AFPT 2. All SFRCS isolation valves of SG 2 from actuation channel 2 will be closed, including the MSIV, the main steam warm-up isolation valve and the MFIVs.

BASES

BACKGROUND (continued)

These Functions are provided in the event the operator determines that an SFRCS Function is needed and does not automatically actuate. These are backup Functions to those performed automatically by SFRCS.

The SFRCS manual initiation circuitry satisfies the manual initiation and single-failure criterion requirements of IEEE-279-1971 (Ref. 1).

APPLICABLE SAFETY ANALYSES

SFRCS Functions credited in the safety analysis are automatic. However, the manual initiation Functions are required by design as backups to the automatic trip Functions and allow operators to initiate AFPT and actuate SG isolation whenever these Functions are needed. Furthermore, the manual initiation of the AFPT and isolation of the SG may be specified in unit operating procedures.

The SFRCS manual initiation Functions are retained for the overall redundancy and diversity of the SFRCS as required by the NRC.

LCO

Each push button performing an SFRCS manual initiation Function shall be OPERABLE. Failure of any push button renders the affected Function inoperable.

One manual initiation push button for each Function (AFPT 1 Initiation (with the exception of ARTS and Main Turbine Trip); AFPT 2 Initiation (with the exception of ARTS and Main Turbine Trip); AFPT 1 Initiation and SG 1 Isolation; and AFPT 2 Initiation and SG 2 Isolation) is required to be OPERABLE whenever the SGs are being relied on to remove heat.

APPLICABILITY

The SFRCS manual initiation Functions shall be OPERABLE in MODES 1, 2, and 3 because the SGs are relied on for Reactor Coolant System heat removal and because SG inventory can be at a sufficiently high energy level to contribute significantly to the peak containment pressure during a secondary pipe break. In MODES 4, 5, and 6, heat removal requirements are reduced and can be provided by the Decay Heat Removal System because the SG energy level is low and secondary side feedwater flow rate is low or nonexistent.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each SFRCS manual initiation Function.

A.1

With one or more SFRCS Functions inoperable the Function must be restored to OPERABLE status within 48 hours. The Completion Time

BASES

ACTIONS

A.1 (continued)

allotted to restore the channel allows the operator to take all the appropriate actions for the failed channel and still ensures that the risk involved in operating with the failed channel is acceptable.

B.1 and B.2

If the Required Action and associated Completion Time is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.12.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST to ensure that the channels can perform their intended functions. The Frequency of 24 months is based on the reliability of the components.

REFERENCES

1. IEEE-279-1971, April 1972.

B 3.3 INSTRUMENTATION

B 3.3.13 Steam and Feedwater Rupture Control System (SFRCS) Actuation

BASES

BACKGROUND

Figure 7.4-4, UFSAR Section 7.4.1.3 (Ref. 1), illustrates SFRCS logic operation. The SFRCS consists of two independent and redundant actuation channels. Each actuation channel consists of two electrically independent complementary logic channels. Each complementary logic channel contains identical sets of SFRCS instrumentation for monitoring key parameters and issuing trip signals when a limiting condition has been reached within the logic channel. The trip output of each complementary logic channel is combined in each actuation channel in a two-out-of-two logic, so that SFRCS will initiate an actuation channel trip if both of the complementary logic channels trip. The logic channel trip will de-energize the SFRCS output relays contained within the actuation channel, making the actual trip logic of each of the two redundant SFRCS actuation channels a two-out-of-two logic.

Auxiliary Feedwater (AFW) Initiation

AFW is initiated to restore a source of cooling water to the steam generators (SGs) when conditions indicate that the normal source of feedwater is insufficient to meet heat removal requirements. A high Feedwater/SG Differential Pressure and a low level in the steam generator indicate a loss of main feedwater (MFW). AFW is initiated and SGs are isolated upon detection of a rupture of a main steam line or MFW line which is sensed when steam pressure reaches the low main steam line pressure setpoint or the differential pressure between the feedwater and SG reaches the high setpoint. On the loss of all reactor coolant pumps (RCPs), the primary system experiences a total loss of forced circulation, AFW is initiated to promote natural circulation.

Auxiliary Feedwater and Main Steam Valve Control

For Main Steam Line Pressure - Low, the AFW discharge valves and main steam valves receive different open or close signals depending on the affected main steam line. Upon a low pressure in main steam line 1, the two actuation channels will align both AFW pumps to provide feedwater to SG 2 and align the main steam supply of both AFW pump turbines to come from SG 2. SFRCS actuation channel 1 will close AFW pump 1 discharge valve to SG 1, open AFW pump 1 discharge valve to SG 2, close AFW pump turbine 1 main steam supply from SG 1 and open AFW pump turbine 1 main steam supply from SG 2. SFRCS actuation channel 2 will close AFW pump 2 discharge valve to SG 1, open AFW

BASES

BACKGROUND (continued)

pump 2 discharge valve to SG 2, close AFW pump turbine 2 main steam supply from SG 1 and open AFW pump turbine 2 main steam supply from SG 2. Upon a low pressure in main steam line 2, the two actuation channels will align both AFW pumps to provide feedwater to SG 1 and align the main steam supply of both AFW pump turbines to come from SG 1. SFRCS actuation channel 1 will open AFW pump 1 discharge valve to SG 1, close AFW pump 1 discharge valve to SG 2, open AFW pump turbine 1 main steam supply from SG 1 and close AFW pump turbine 1 main steam supply from SG 2. SFRCS actuation channel 2 will open AFW pump 2 discharge valve to SG 1, close AFW pump 2 discharge valve to SG 2, open AFW pump turbine 2 main steam supply from SG 1 and close AFW pump turbine 2 main steam supply from SG 2.

Main Steam line and MFW isolation is provided by the Main Steam Line Pressure - Low trip and the Feedwater/SG Differential Pressure - High trip. Once isolation of the SGs has occurred, manual action is required to defeat the isolation command as desired.

Main Steam Line Isolation

The Main Steam Isolation Function is accomplished by closing the main steam isolation valves (MSIVs) and the turbine stop valves (TSVs). The TSVs serve as a backup to the MSIVs.

Main Feedwater Isolation

The MFW Isolation Function limits the mass and energy released to containment following a MSLB or MFWLB, and is accomplished by closing the main feedwater stop valves (MFSVs), the main feedwater control valves (MFCVs), and the startup feedwater control valves (SFCVs). While this Function also closes the MFW block valves, it is not required for this Function to be OPERABLE (the MFW block valves are not required to mitigate any accident and are not credited in any safety analysis).

APPLICABLE SAFETY ANALYSES

The MFW line break analysis assumes the Feedwater/Steam Generator Differential Pressure - High trip isolates the unaffected steam generator from the line break thus assuring adequate inventory and pressure to run the available AFW pump turbines. The analysis further assumes that the Main Steam Line Pressure - Low trip realigns the AFW System to take steam from and to feed the unaffected steam generator should the MFWLB affect the integrity of one of the SGs.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSLB analysis assumes the Main Steam Line Pressure - Low trip isolates the unaffected steam generator from the line break thus assuring adequate inventory and pressure to run the available AFW pump turbines. The analysis further assumes that the Main Steam Line Pressure - Low trip realigns the AFW System to take steam from and to feed the unaffected steam generator.

The Main Steam Isolation Function is accomplished by closing the main steam isolation valves (MSIVs) and the turbine stop valves (TSVs). The TSVs serve as a backup to the MSIVs. Closure of the TSVs ensures that both steam generators do not blowdown following a MSLB in conjunction with a failure of the affected steam generator's associated MSIV failing to close.

The Main Feedwater Isolation Function is accomplished by closing the MFSVs, the MFCVs, and the SFCVs. While this Function also closes the MFW block valves, it is not required for this Function to be OPERABLE.

The Loss of Feedwater (LOFW) analysis assumes the Steam Generator Level - Low trip initiates the AFW System.

The SFRCS Actuation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two channels each of Auxiliary Feedwater Initiation, Auxiliary Feedwater and Main Steam Valve Control, Main Steam Line Isolation, and Main Feedwater Isolation Actuation logics shall be OPERABLE. There are only two channels of automatic actuation logic per Function. Therefore, violation of this LCO could result in a complete loss of the automatic Function assuming a single failure of the other channel.

APPLICABILITY

Auxiliary Feedwater Initiation, Auxiliary Feedwater and Main Steam Valve Control, Main Steam Line Isolation, and Main Feedwater Isolation Actuation logics shall be OPERABLE in MODES 1, 2, and 3 because SG inventory can be at a high energy level and can contribute significantly to the peak containment pressure during a secondary side line break. In MODES 4, 5, and 6, the energy level is low and the secondary side feedwater flow rate is low or nonexistent.

ACTIONS

For this LCO, a Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each SFRCS logic Function.

BASES

ACTIONS (continued)

A.1

Condition A applies when one or more SFRCS Logic Functions in a single channel are inoperable (i.e., channel 1 could be inoperable for all four SFRCS Logic Functions and Condition A would still be applicable) with all Logic Functions in the other channel OPERABLE. This Condition is equivalent to failure of one AFW, Main Steam Line Isolation, and MFW Isolation train.

With one channel of one or more SFRCS Logic Functions inoperable, the associated SFRCS train must be restored to OPERABLE status. Since there are only two automatic actuation logic channels per SFRCS Function, the condition of one channel inoperable is analogous to having one train of a two train Engineered Safety Feature (ESF) System inoperable. The system safety function can be accomplished; however, a single failure cannot be taken. Therefore, the failed channel(s) must be restored to OPERABLE status to re-establish the system's single-failure tolerance.

Condition A can be thought of as equivalent to failure of a single train of a two train safety system (e.g., the safety function can be accomplished, but a single failure cannot be taken). Thus, the Completion Time of 72 hours has been chosen to be consistent with Completion Times for restoring one inoperable ESF System train.

The SFRCS has not been analyzed for failure of Logic Functions in both channels. In this condition, the potential for system interactions that disable heat removal capability on AFW has not been evaluated. Consequently, any combination of failures in both channels 1 and 2 is not covered by Condition A and must be addressed by entry into LCO 3.0.3.

B.1 and B.2

If Required Action A.1 cannot be met within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.13.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST to ensure that the channels can perform their intended functions. This test verifies MFW and Main Steam Line Isolation; AFW Initiation; and Auxiliary Feedwater and Main Steam Valve Control are functional. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. This test simulates the required inputs to the logic circuit and verifies successful operation of the automatic actuation logic. The test need not include actuation of the end device. This is due to the risk of a unit transient caused by the closure of valves associated with MFW and Main Steam Line Isolation or actuation of AFW during testing at power. The Frequency of 31 days is based on operating experience, which has demonstrated the rarity of more than one channel failing within the same 31 day interval.

This SR is modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of the CHANNEL FUNCTIONAL TEST, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the other actuation channel is OPERABLE. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This is acceptable since the other actuation channel will continue to ensure the associated SFRCS Function can perform its assumed function.

REFERENCES

1. UFSAR, Section 7.4.1.3.

B 3.3 INSTRUMENTATION

B 3.3.14 Fuel Handling Exhaust - High Radiation

BASES

BACKGROUND	The Fuel Handling Exhaust - High Radiation instrumentation consists of two redundant channels. The two redundant channels monitor the radiation levels in the Fuel Handling Area Ventilation System (FHAVS) exhaust ductwork. If the radiation levels exceed the setpoint, the FHAVS and the Spent Fuel Pool Area Emergency Ventilation System (EVS) receive a signal from one radiation monitor. The FHAVS supply and exhaust fans will trip and their inlet and outlet dampers will isolate. The Station EVS fans start and will maintain a negative pressure in the spent fuel pool area and filter the exhaust through charcoal filters and high efficiency particulate air (HEPA) filters. Filtration of the exhaust ensures the accident dose at the site boundary will be well below the 10 CFR 100 limits. The measurement range of the radiation monitors is 0.1 to 10^7 mr/hr. The trip setpoint for the alarm and actuation function is $\leq$ 2 times the background. Background for this specification is defined as the design radiation levels for normal operation. The design radiation levels are shown on UFSAR, Figure 12.1-4 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The Fuel Handling Exhaust - High Radiation Function has been assumed in the fuel handling accident outside containment analysis (Ref. 2). The Spent Fuel Pool Area EVS actuation aligns the ventilation flow path through the HEPA and charcoal filters prior to discharging to the station vent. Fuel Handling Exhaust - High Radiation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requires two channels of Fuel Handling Exhaust - High Radiation to be OPERABLE. Failure of any channel renders the associated Spent Fuel Pool Area EVS train inoperable. These channels are required to monitor the radiation levels in the fuel storage pool area and building. Both channels are required to support OPERABILITY of the Spent Fuel Pool Area EVS to ensure alignment through the HEPA and charcoal filter systems in the event of a fuel handling accident. The trip setpoints are specified for each Fuel Handling Exhaust - High Radiation channel in SR 3.3.14.3. Nominal trip setpoints are specified in the Radiation Monitor Setpoint Manual. The nominal setpoints are based on the UFSAR design normal radiation levels and are set to ensure that conditions are well within the limits of 10 CFR 100.

BASES

APPLICABILITY

Two Fuel Handling Exhaust - High Radiation channels are required to be OPERABLE during movement of irradiated fuel assemblies in the spent fuel pool building to ensure radiation doses are within the limits of the accident analyses.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1

Condition A applies when one or more channel(s) are inoperable. These radiation monitors are required to be OPERABLE in support of LCO 3.7.13, "Spent Fuel Pool Area Emergency Ventilation System (EVS)." If Condition A applies, LCO 3.7.13 Conditions and Required Actions must immediately be applied.

SURVEILLANCE REQUIREMENTS

SR 3.3.14.1

Performance of the CHANNEL CHECK every 12 hours ensures a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction.

The Frequency of every 12 hours is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.14.1 (continued)

CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel operability during normal operational use of the displays associated with the LCO's required channels.

SR 3.3.14.2

A CHANNEL FUNCTIONAL TEST is performed on each required Fuel Handling Exhaust - High Radiation channel to ensure the entire channel will perform the intended function.

The Frequency of 31 days is based on unit operating experience, with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is a rare event.

SR 3.3.14.3

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to a setpoint specified in the Radiation Monitoring Setpoint Manual, which is significantly less than the required Trip Setpoint. This combined with the specified equipment tolerance ensures that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the unit specific setpoint and tolerance.

This 18 month Frequency is based on operating experience.

REFERENCES

1. UFSAR, Figure 12.1-4.

2. UFSAR, Section 15.4.7.

B 3.3 INSTRUMENTATION

B 3.3.15 Station Vent Normal Range Radiation Monitoring

BASES

BACKGROUND

The principal function of the Station Vent Normal Range Radiation Monitoring instrumentation is to provide an enclosed environment from which the unit can be operated following an uncontrolled release of radioactivity. The high radiation isolation function provides assurance that under the required conditions, an isolation signal will be given. The radiation monitors located in the station vent stack provide isolation and shutdown of the Control Room Normal Ventilation System.

The control room isolation signal is provided by two normal range radiation monitors that continuously monitor the station vent for particulate, iodine, and gross gaseous radioactivity. Each normal range monitor consists of two filter-detectors, a paper filter beta scintillation detector particulate channel and a charcoal filter gamma scintillation detector iodine channel, plus a beta sensitive noble gas channel. Only the noble gas monitors are required to satisfy the requirements of this LCO. The station vent normal range radiation monitors actuate to isolate the Control Room Normal Ventilation System. The Control Room Emergency Ventilation System (CREVS) is manually operated after the station vent normal range radiation high setpoint is exceeded. An isolation signal from either monitor will result in an isolation of the Control Room Normal Ventilation System. The Station Vent Normal Range Radiation Monitoring performs an additional function on ensuring the average annual gaseous effluent concentrations at the boundary of the unrestricted area do not exceed 10 CFR 20 requirements. The setpoints for limiting the offsite dose are more limiting than would be required for control room isolation purposes. The detector setpoints are established so as not to exceed the offsite dose limits required by the Offsite Dose Calculation Manual (ODCM). This bounds the Technical Specification reason for the detectors.

APPLICABLE SAFETY ANALYSES

The Control Room Normal Ventilation System is isolated when a Containment Pressure - High or Reactor Coolant System Pressure - Low Safety Features Actuation System signal is received, or a Station Vent Normal Range Radiation Monitoring high radiation signal is received. The CREVS can be operated in either the recirculation mode or the outside air intake mode. In both cases, the air flows through charcoal and HEPA filters that have a total efficiency ≥ 95 percent. The fuel handling accident analyses, both inside and outside of containment, assume the Control Room Normal Ventilation System is isolated by the Station Vent Normal Range Radiation Monitoring high radiation signal.

The Station Vent Normal Range Radiation Monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The Station Vent Normal Range Radiation Monitoring instrumentation measures radiation levels in the station vent. A high radiation level may pose a threat to the control room personnel; therefore, the Control Room Normal Ventilation System is automatically isolated.

The Station Vent Normal Range Radiation Monitoring channels consist of two station vent normal range noble gas radiation monitors. Two channels of Station Vent Normal Range Radiation Monitoring are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation of the Control Room Normal Ventilation System. The detector setpoints are established so as not to exceed the offsite dose limits required by the ODCM, and any setpoint for control room isolation is bounded by the setpoints for offsite dose limits.

APPLICABILITY

The control room isolation capability on high radiation shall be OPERABLE whenever there is a chance for a significant accidental release of radioactivity. This includes MODES 1, 2, 3, and 4, and during movement of irradiated fuel. If a radioactive release were to occur during any of these conditions, the control room would have to remain habitable to ensure reactor shutdown and cooling can be controlled from the control room.

ACTIONS

A.1 and A.2

With one channel of Station Vent Normal Range Radiation Monitoring inoperable, action must be taken within 7 days to place the Control Room Normal Ventilation System and CREVS in a condition that does not require the isolation to occur. To ensure that the ventilation system has been placed in a state equivalent to that which occurs after the high radiation isolation has occurred, the Control Room Normal Ventilation System is isolated and one OPERABLE train of the CREVS is placed in operation. However, as Noted (Required Action A.2 Note), CREVS is only required to be placed in operation in MODES 1, 2, 3, and 4, consistent with the CREVS Specification (CREVS is only required to be OPERABLE in MODES 1, 2, 3, and 4 as described in the Bases of LCO 3.7.10, "Control Room Emergency Ventilation System (CREVS)"). Plant operation may continue indefinitely in this state provided that control room temperature can be maintained in an acceptable range with the CREVS obtaining fresh air makeup as described in UFSAR, Section 9.4.1 (Ref. 1). The 7 day Completion Time is based on the low probability of a DBA occurring during this time period and the ability of the remaining Station Vent Normal Range Radiation Monitoring channel to provide its intended function.

BASES

ACTIONS (continued)

B.1 and B.2

With two channels inoperable, action must be taken within 1 hour to place the Control Room Normal Ventilation System and CREVS in a condition that does not require the isolation to occur. To ensure that the ventilation systems have been placed in a state equivalent to that which occurs after the high radiation isolation has occurred, the Control Room Normal Ventilation System is isolated and one OPERABLE train of the CREVS is placed in operation. However, as Noted (Required Action B.2 Note), CREVS is only required to be placed in operation in MODES 1, 2, 3, and 4, consistent with the CREVS Specification (CREVS is only required to be OPERABLE in MODES 1, 2, 3, and 4 as described in the Bases of LCO 3.7.10). Plant operation may continue indefinitely in this state provided that control room temperature can be maintained in an acceptable range with the CREVS obtaining fresh air makeup as described in UFSAR, Section 9.4.1 (Ref. 1). The 1 hour Completion Time is a sufficient amount of time in which to take the Required Action.

C.1 and C.2

If the Control Room Normal Ventilation System can not be isolated or the CREVS cannot be placed in operation while in MODE 1, 2, 3, or 4, actions must be taken to minimize the chances of an accident that could lead to radiation releases. The unit must be placed in at least MODE 3 within 6 hours, with a subsequent cooldown to MODE 5 within 36 hours. This places the reactor in a low energy state that allows greater time for operator action if habitation of the control room is precluded. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

If the Control Room Normal Ventilation System can not be isolated during movement of irradiated fuel assemblies, then Required Action D.1 requires the suspension of actions that could lead to an accident that could release radioactivity resulting from a fuel handling accident.

Required Action D.1 places the core in a safe and stable configuration in which it is less likely to experience an accident that could result in a significant release of radioactivity. The plant must be maintained in this

BASES

ACTIONS

D.1 (continued)

condition until the automatic isolation capability is returned to operation or when manual action isolates the Control Room Normal Ventilation System. The Completion Time of "Immediately" for Required Action D.1 is consistent with the urgency of the situation and accounts for the high radiation function, which provides the only automatic control room isolation function capable of responding to radiation release due to a fuel handling accident. The Completion Time does not preclude placing any fuel assembly into a safe position before ceasing any such movement.

SURVEILLANCE REQUIREMENTS

SR 3.3.15.1

SR 3.3.15.1 is the performance of a CHANNEL CHECK for the Station Vent Normal Range Radiation monitoring actuation instrumentation once every 12 hours to ensure that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. The Frequency, 12 hours, is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal but more frequent checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels.

SR 3.3.15.2

The Surveillance is modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of the required CHANNEL FUNCTIONAL TEST, entry into the associated Conditions and Required Actions may be delayed for up to 3 hours, provided the other channel is OPERABLE. Upon completion of the Surveillance, or

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.15.2 (continued)

expiration of the 3 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This is based on the average time required to perform channel surveillance. It is not acceptable to routinely remove channels from service for more than 3 hours to perform required surveillance testing.

SR 3.3.15.2 is the performance of a CHANNEL FUNCTIONAL TEST once every 92 days to ensure that the channels can perform their intended functions. This test verifies the capability of the instrumentation to provide the automatic control room isolation.

The Frequency of 92 days is based on the known reliability of the equipment and the available two channel redundancy.

SR 3.3.15.3

The CHANEL CALIBRATION is performed every 18 months. CHANNEL CALIBRATION is a complete check of the instrument loop and the detector. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to a setpoint specified in the Radiation Monitoring Setpoint Manual, which is significantly less than the value required to isolate Control Room Normal Ventilation to control dose to the 10 CFR 20, Appendix B limits. This combined with the specified equipment accuracy ensures that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the unit specific setpoint and accuracy.

The Frequency of 18 months is acceptable based on operational experience.

REFERENCES

1. UFSAR, Section 9.4.1.

B 3.3 INSTRUMENTATION

B 3.3.16 Anticipatory Reactor Trip System (ARTS) Instrumentation

BASES

BACKGROUND

The purpose of the ARTS is to initiate a reactor trip when a sensed parameter exceeds its setpoint value, indicating the approach of an unsafe condition thereby reducing the magnitude of pressure and temperature transients on the Reactor Coolant System (RCS) caused by loss of main feedwater events or turbine trips. This lowers the probability of a Pressurizer Pilot Operated Relief Valve (PORV) actuation during these events. The ARTS was added to the B&W designed plants in accordance with NUREG-0737 (Ref. 1) following the Three Mile Island Unit 2 accident.

The ARTS consists of four separate redundant protection channels that receive inputs of main feedwater (MFW) pump status and turbine status. Figure 7.4-8, UFSAR, Section 7.4.1.4 (Ref. 2), shows the arrangement of a typical ARTS protection channel. A protection channel is composed of measurement channels, a trip logic module, and CONTROL ROD drive (CRD) trip devices. These channels encompass all equipment and electronics from the point at which the measured parameter is sensed through the bistable relay contacts in the trip string. The ARTS instrumentation measures critical unit parameters and compares these to predetermined setpoints. If the setpoint is exceeded, a channel trip signal is generated. A channel trip signal is generated when the turbine generator is tripped or when both MFW pump turbines are tripped. The trip devices for the ARTS and the Reactor Protection System (RPS) are the same. LCO 3.3.4, "CONTROL ROD DRIVE (CRD) Trip Devices," provides the requirements for the CRD trip devices.

The ARTS consists of four independent protection channels, each containing a logic trip module. The logic trip module receives signals from its own measurement channels that indicate a protection channel trip is required. The logic trip module transmits this signal to its own two-out-of-four trip logic and to the two-out-of-four logic of the logic trip modules in the other three ARTS protective channels. Whenever any two ARTS channels transmit channel trip signals, the logic trip module in each channel actuates to remove 120 VAC power from its associated CRD trip breaker.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

ARTS was installed to satisfy Item II.K.2.10.f of NUREG-0737 (Ref. 1). The anticipatory trip will operate in advance of the RPS RC High Pressure trip to reduce the peak RCS pressure and thus reduce challenges to the PORV.

ARTS is not credited to mitigate any accident analyses in the UFSAR. It is retained to be consistent with NUREG-1430.

Turbine Trip

Main turbine stop valve oil pressure is the input for the Turbine Trip Function. The inputs to the ARTS are provided by four pressure switches that measure the oil pressure at the fast acting solenoids for the turbine generator main stop valves. One pressure switch is associated with each ARTS protection channel. The Turbine Trip Function trips the reactor when the main turbine is lost at high power levels. The Turbine Trip Function provides an early reactor trip in anticipation of the loss of heat sink associated with a turbine trip. This trip is activated at higher power levels, thereby limiting the range through which the Integrated Control System must provide an automatic runback on a turbine trip.

Each of the four turbine oil pressure channels feeds all four protection channels through buffers that continuously monitor the status of the contacts. Therefore, failure of any pressure switch affects all protection channels. However, since the logic is such that any two channels can provide a turbine trip to all four output logics, only three of the four turbine trip channels are required to be OPERABLE.

For the main turbine stop valve oil pressure channel, the nominal trip setpoint is selected to provide a trip signal indicative of a main turbine trip. An automatic bypass of the channels is provided, and the bypass is set to ensure that the trip is enabled as required by the LCO.

Trip of Both Main Feed Pump Turbines

Feedwater pump turbine high pressure stop valve control oil pressure is an input to the Trip of Both Main Feed Pump Turbines Function. Control oil pressure is measured at the high pressure stop valves by four switches on each feedwater pump. One switch on each pump is associated with each protection channel. Each channel consists of two switches, one from each main feed pump turbine. The Trip of Both Main Feed Pump Turbines Function provides a reactor trip during MODE 1 operation when both main feedwater (MFW) pump turbines are lost. The trip provides an early reactor trip in anticipation of the loss of heat sink associated with the loss of normal feedwater event.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

Each of the four main feed pump turbine oil pressure channels feeds all four protection channels through buffers that continuously monitor the status of the contacts. Therefore, failure of any pressure switch affects all protection channels. However, since the logic is such that any two channels can provide a loss of both main feed pump turbine trip to all four output logics, only three of the four channels (with each channel consisting of a pressure switch from both main feed pump turbines) are required to be OPERABLE.

For the feedwater pump turbine high pressure stop valve control oil pressure switches, the nominal trip setpoint is selected to provide a trip signal indicative of a MFW pump trip.

Output Logic

To ensure an ARTS trip will occur, the output logic that sends the trip signals to the CRD trip breakers must be OPERABLE. When a two-out-of-four trip condition exists, the associated output logic actuates to remove 120 VAC power from its associated CRD trip breaker. Two of the output logic channels remove power from CRD trip breakers in one division, while the other two output logic channels remove power from CRD trip breakers in the other division. One output logic channel in each division must trip for a reactor trip to occur.

All four ARTS logic output channels are required to be OPERABLE to ensure that a reactor trip will occur if needed in MODE 1. OPERABILITY of the logic output channel ensures its capability to receive and interpret trip signals from each ARTS Function and to send appropriate signals to open its associated trip devices. The requirement of four ARTS logic output channels to be OPERABLE ensures that no single ARTS logic output channel failure can preclude an ARTS trip via the CRD trip breakers.

ACTIONS

Required Actions A and B apply to all ARTS instrumentation Functions listed in Table 3.3.16-1.

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each Function.

When the number of inoperable channels in a trip Function exceeds those specified in ACTION A, then the unit is outside the analysis assumptions. Therefore, LCO 3.0.3 shall be immediately entered if applicable in the current MODE of operation.

BASES

ACTIONS (continued)

A.1 and A.2

Condition A applies when one required channel becomes inoperable in one or more Functions.

Required Action A.1 applies to Function 3, the Output Logic Function. When one Output Logic Function channel is inoperable, the associated control rod drive trip breaker must be tripped within 1 hour. This ensures the function of the output logic is met.

Required Action A.2 applies to Functions 1 and 2, the Turbine Trip and Trip of Both Feed Pump Turbines Functions. When one required channel of either of these Functions is inoperable, the inoperable channel must be restored to OPERABLE status within 72 hours. While in this condition, the remaining two channels of the associated Function can still cause a reactor trip, however, redundancy is lost since an additional single failure in the Function will result in loss of ARTS capability from the Function.

B.1 and B.2

When Required Action A.1 or A.2 is not met within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to $\leq$ 45% RTP within 6 hours (for Function 1) and the unit must be brought to at least MODE 2 within 6 hours (for Functions 2 and 3). The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

The SRs for each ARTS Function are identified by the SRs column of Table 3.3.16-1 for that Function. The SRs are modified by a Note. The Note directs the reader to Table 3.3.16-1 to determine the correct SRs to perform for each ARTS Function.

SR 3.3.16.1

Performance of the CHANNEL CHECK every 12 hours ensures a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.16.1 (continued)

one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction.

The Frequency of every 12 hours is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel operability during normal operational use of the displays associated with the LCO's required channels.

SR 3.3.16.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable if all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions

The Frequency of 23 days on a STAGGERED TEST BASIS for Function 3 is consistent with the calculations of Reference 3 that indicate the ARTS Output Logic Function retains a high level of reliability for this test interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.16.3

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the unit specific setpoint and tolerance.

The Frequency of 46 days on a STAGGERED TEST BASIS for Functions 1 and 2 is consistent with the calculations of Reference 4 that indicate the ARTS sensors retain a high level of reliability for this test interval. For this SR, *n* equals 4, since there are 4 total channels per Function.

REFERENCES

1. NUREG-0737, November 1979.

2. UFSAR, Section 7.4.1.4 and Figure 7.4-8.

3. NRC SER for BAW-10167, Supplement 3, January 7, 1998.

4. NRC SER for BAW-10167, Supplement 2, July 8, 1992.

B 3.3 INSTRUMENTATION

B 3.3.17 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events.

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed, and so that the need for and magnitude of further actions can be determined. These essential instruments are identified by UFSAR Section 7.13 (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO equate to two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category 1 variables.

These key variables are identified by unit specific Regulatory Guide 1.97 analysis (Ref. 1). This analysis identifies the unit specific Type A and Category 1 variables and provides justification for deviating from the NRC guidance in Reference 2.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the availability of information so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures. These variables are restricted to preplanned actions for the primary success path of DBAs (e.g., loss of coolant accident (LOCA));
- Take the specified, preplanned, manually controlled actions, for which no automatic control is provided, which are required for safety systems to accomplish their safety functions;
- Determine whether systems important to safety are performing their intended functions;

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and estimate the magnitude of any impending threat.

The unit specific Regulatory Guide 1.97 analysis documents the process that identifies Type A and Category 1 non-Type A variables.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category 1, non-type A, instrumentation must be retained in Technical Specifications because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category 1, non-Type A variables are important for reducing public risk.

LCO

LCO 3.3.17 requires two OPERABLE channels for most Functions to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident.

One exception to the two channel requirement is Penetration Flow Path Containment Isolation Valve Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active containment isolation valve. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of the passive valve or via system boundary status. If a normally active containment isolation valve is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

The following list is a discussion of the specified instrument Functions listed in Table 3.3.17-1.

1. <u>Wide Range Neutron Flux</u>

   Wide Range Neutron Flux is a Category 1 variable provided to verify reactor shutdown. Wide Range Neutron Flux instrumentation consists of two channels; each consisting of a fission chamber detector providing continuous indication at a PAM panel located in the control room. This signal is processed for a wide range of 1E-8% power to 2E2% power.

BASES

LCO (continued)

2. Reactor Coolant Loop Outlet Temperature

Reactor Coolant Loop Outlet Temperature monitors the hot leg and is a Type A Category 1 variable provided for verification of core cooling and long term surveillance. Reactor Coolant Loop Outlet Temperature consists of two channels per reactor coolant loop. Each channel consists of a resistance temperature detector located in thermowell providing continuous indication on the PAM panel in the control room. The channels provide indication over a range of 120°F to 920°F.

3. Reactor Coolant Loop Pressure

Reactor Coolant Loop Pressure is a Type A and Category 1 variable provided for verification of core cooling and RCS integrity long term surveillance.

Wide range reactor coolant loop pressure is measured by pressure transmitters with a span of 0 psig to 3000 psig. Redundant monitoring capability is provided in each loop measured by pressure transmitters with a span of 0 psig to 2500 psig. Control room indications are provided on the PAM panel and other control panels in the control room.

4. Reactor Coolant Hot Leg Level (Wide Range)

Reactor Coolant Hot Leg Level (Wide Range) is a Category 1 variable provided for verification and long term surveillance of core cooling. The Reactor Coolant Hot Leg Level (Wide Range) provides a means to trend reactor coolant inventory and provides supplementary information to assist the operator in the assessment of the effectiveness of automatic safety functions.

Reactor Vessel Water Level channels consist of two channels (one per hot leg); each with a differential pressure transmitter measuring the differential pressure between the top and bottom of the associated hot leg and compensating for the density of water. The sensing line fluid density compensation allows for variation in fluid density resulting from variation in the containment ambient temperature. This feature is accomplished by utilizing thermistor wire that tracks the entire length of the instrument reference leg. The signal is processed from a range of 0 inches to 968 inches. Level transmitters with a differential pressure range of 0 inches to 968 inches water measure the differential pressure between the upper tap reference leg (at the steam generator inlet) and the lower tap (hot leg at the reactor outlet). The transmitter and density

BASES

LCO (continued)

compensation signal are sent to the plant computer. A computer algorithm takes these signals along with temperature and pressure signals and executes to determine actual hot leg level. The level can be accessed and displayed provided that the RCS pumps are off and rapid depressurization is not occurring.

5. Containment Water Level (Wide Range)

Containment Water Level (Wide Range) is a Category 1 variable provided for verification and long term surveillance of RCS integrity. Containment Water Level instrumentation consists of two channels. Each channel consists of a level transmitter with output to an indicator. The wide range containment water level monitors have an indicator on the PAM panel in the control room with a range of 0 feet to 55 feet.

6. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is a Type A and Category 1 variable provided for verification of RCS and containment OPERABILITY. Containment Pressure instrumentation consists of two channels. Each channel consists of a pressure transmitter with output to an indicator on the PAM panel in the control room. The indicators provide indication with a range of 0 psia to 200 psia.

7. Penetration Flow Path Containment Isolation Valve Position

Penetration Flow Path Containment Isolation Valve (CIV) (excluding check valves) Position is a Category 1 variable provided for verification of containment OPERABILITY.

CIV position is provided for verification of containment integrity. In the case of CIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position

BASES

LCO (continued)

indication for the CIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. Each penetration is treated separately and each penetration flow path is considered a separate function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

The Penetration Flow Path CIV Position PAM instrumentation consists of position switches mounted on the valves for the positions to be indicated, associated wiring, and control room indicating lamps for active CIVs (i.e., automatic CIV - check valves are not required to have position indication). These position switches and associated indicators in the control room provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

8. Containment High Range Radiation

Containment High Range Radiation is a Category 1 variable provided to monitor the potential for significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment High Range Radiation instrumentation consists of two channels. Each channel consists of one gamma photon radiation detector with a calibrated range of 1E0 R/hr to 1E8 R/hr. Continuous indicators have been provided in the PAM panel located in the control room. In addition, both strings provide an output to recorders in the radiation monitoring panels located in the control room.

9. Pressurizer Level

Pressurizer Level is a Type A and Category 1 variable used to aid in determining whether to terminate Emergency Core Cooling Systems (ECCS), if still in progress, or to reinitiate ECCS if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition. Pressurizer Level instrumentation consists of two channels. Each channel consists of a pressurizer level transmitter with an indicator in the control room. The indicators have a 0 inches to 320 inches range.

BASES

LCO (continued)

10. Steam Generator Startup Range Level

Steam Generator Startup Range Level is a Category 1 variable provided to monitor operation of decay heat removal via the SG. The indication of SG level is the extended startup range level instrumentation, covering a span of approximately 8 inches to 396 inches above the lower tube sheet. Steam Generator Startup Range Level consists of two channels per steam generator. Two readouts are 0 inches to 250 inches of water, two are 0 inches to 300 inches of water. Indicators are provided on the PAM panel and another control panel in the control room.

If the Steam and Feedwater Rupture Control System has actuated, and either the Safety Features Actuation System (SFAS) level 2 has actuated or if Subcooling Margin is not adequate, then the Auxiliary Feedwater (AFW) System is used to maintain steam generator water level at the SFAS high level setpoint, to promote boiler-condenser heat transfer. The Main Feedwater System can be used, if available, if the AFW System is not available.

11. Incore Thermocouples

Incore Thermocouples is a Category 1 variable provided for assessing the existence of inadequate core cooling.

There are two channels of incore thermocouples per core quadrant. Each channel consists of two thermocouples, selectable for each indicator and T_{sat} meter located on the PAM panels. One thermocouple per channel is required for OPERABILITY. The thermocouples are redundant to the hot leg RTD's. The switch and temperature indicators are located in the control room. The range of the thermocouples is 0ºF to 2300ºF.

12. Auxiliary Feedwater Flow Rate

AFW Flow Rate is a Category 1 variable provided to monitor operation of decay heat removal via the SGs. The AFW Flow to each SG is determined from a differential pressure measurement calibrated to a span of 0 gpm to 1000 gpm associated with each SG. Redundant monitoring capability is provided by two independent trains of instrumentation for each SG. One differential pressure transmitter provides an input to a control room indicator on the PAM panels and the other provides indication to the control room panels.

BASES

LCO (continued)

AFW Flow is the primary indication used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

13. Steam Generator Outlet Steam Pressure

Steam Generator Outlet Steam Pressure is a Category 1 variable provided to monitor operation of decay heat removal via the SG. Steam Generator Outlet Steam Pressure instrumentation consists of two (one per Steam Generator) channels with indicators in the control room and corresponding plant computer points. The range of these channels is 0 psig to 1200 psig.

14. High Pressure Injection Flow

High Pressure Injection Flow instrumentation is a Type A and Category 1 variable provided to monitor the status of the high pressure injection. There is one channel for each HPI injection line with indicators in the control room. The channels have a 0 gpm to 500 gpm range.

15. Low Pressure Injection (Decay Heat Removal) Flow

Low Pressure Injection (Decay Heat Removal) Flow is a Type A and Category 1 variable used to monitor the status of the low pressure injection (decay heat removal) train. There are two channels; one for each train with indicators in the control room. These channels have a 0 gpm to 5000 gpm range.

16. Borated Water Storage Tank Level

Borated Water Storage Tank (BWST) Level is a Type A and Category 1 variable used to monitor the level in the BWST. Level instrumentation consists of four level strings with indicators in the control room. Only two channels are required to satisfy this LCO. The range of these strings is 0 feet to 50 feet.

17. Neutron Flux (Source Range)

Source Range Neutron Flux is a Category 1 variable provided to verify the reactor is subcritical. Source Range Neutron Flux instrumentation consists of two channels. Each channel consists of a fission chamber with a range from 1E-1 cps to 1E5 cps. Continuous indicators have been provided in the PAM panels located in the control room.

BASES

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event occurring that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note is added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.17-1. The Completion Time(s) of the inoperable channels of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

When one or more Functions have one required channel inoperable, the inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience. This takes into account the remaining OPERABLE channel (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time of Condition A are not met. Required Action B.1 specifies immediate initiation of action described in Specification 5.6.5, "Post Accident Monitoring report," which requires a written report to be submitted to the NRC. This report discusses the results of the evaluation into the cause of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability and given the likelihood of unit conditions that would require information provided by this instrumentation. As Noted, Required Action B.1 is only applicable for Functions other than Functions 13, 14, and 15.

Required Action B.2 directs entry in the appropriate Condition referenced in Table 3.3.17-1. The applicable Condition in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition A and the associated Completion Time has expired, Required Action B.2 is entered for that channel and provides for transfer

BASES

ACTIONS

B.1 and B.2 (continued)

to the appropriate subsequent Condition. As noted, Required Action B.2 is only applicable for Functions 13, 14, and 15, as these are the only Functions with only one required channel. Since these Functions have only one channel, continued operations past the 30 days of ACTION A is not allowed.

The Completion Time of "Immediately" for Required Actions B.1 and B.2 ensures the requirements of Specification 5.6.5 are initiated or the proper Condition dictated by Table 3.3.17-1 is entered.

C.1

When one or more Functions have two required channels inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrumentation action operation and the availability of alternative means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance of qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.17-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

If the Required Action and associated Completion Time of Condition A (for Functions 13, 14, and 15) or C (for all other Functions) is not met and Table 3.3.17-1 directs entry into Condition E, the unit must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours

BASES

ACTIONS

E.1 (continued)

and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1

At this unit, alternative means of monitoring Containment High Range Radiation have been developed and tested. These alternative means may be temporarily used if the normal PAM channel cannot be restored to OPERABLE status within the allowed time.

If these alternative means are used, the Required Action is not to shut the unit down, but rather to follow the directions of Specification 5.6.5, in the Administrative Controls section of the Technical Specifications. The report provided to the NRC should discuss the alternative means used, describe the degree to which the alternative means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

At this unit, the alternative monitoring provisions consist of the Containment Vessel Area Radiation Elements or Containment Normal Range Noble Gas Channels.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs apply to each PAM instrumentation Function in Table 3.3.17-1 except as stated in the SR.

SR 3.3.17.1

Performance of the CHANNEL CHECK once every 31 days for each required instrumentation channel that is normally energized ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel with a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.17.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Offscale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency is based on unit operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal but more frequent checks of channels during normal operational use of the displays associated with this LCO's required channels.

SR 3.3.17.2

A CHANNEL CALIBRATION is performed every 18 months. CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. This test verifies the channel responds to measured parameters within the necessary range and accuracy.

A Note clarifies that the neutron detectors are not required to be tested as part of the CHANNEL CALIBRATION. There is no adjustment that can be made to the detectors. Furthermore, adjustment of the detectors is unnecessary because they are passive devices, with minimal drift.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Incore Thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

The Frequency is based on operating experience and is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.17.3

A CHANNEL CALIBRATION is performed every 24 months. CHANNEL CAILIBRATION is a complete check of the instrument channel, including the sensor. This test verifies the channel responds to measured parameters within the necessary range and accuracy.

For the Containment High Range Radiation Monitors, a CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr, and a one point calibration check of the detector below 10 R/hr with a gamma source.

The Frequency is based on operating experience and consistency with the typical industry refueling cycle and is justified by an assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift.

REFERENCES

1. UFSAR, Section 7.13.

2. Regulatory Guide 1.97.

3. NUREG-0737, 1979.

B 3.3 INSTRUMENTATION

B 3.3.18 Remote Shutdown System

BASES

BACKGROUND

The remote shutdown monitoring instrumentation provides the control room operator with sufficient instrumentation to support maintaining the unit in a safe shutdown condition from locations other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the main steam safety valves (MSSVs) or the steam generator (SG) atmospheric vent valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish monitoring at the auxiliary shutdown panel and maintain the unit in MODE 3. Not all necessary remote shutdown monitoring instrumentation is located at the auxiliary shutdown panel. Some are located at the reactor trip breakers and on the control rod drive logic cabinets. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the remote shutdown monitoring instrumentation Functions ensures that there is sufficient information available on selected unit parameters to maintain the unit in MODE 3 should the control room become inaccessible.

The control circuits and transfer switches are used to meet 10 CFR 50 Appendix R (Ref. 2) requirements. A serious control room or cable spreading room fire will render the control room uninhabitable, and can also cause spurious operation and loss of electrical control for certain components. The circuits and switches are used to shift control of components from the control room such that the component can be controlled only from either the remote shutdown panel or another local location when a serious control room or cable spreading room fire renders the control room uninhabitable and control of the components is required in order to achieve and maintain safe shutdown of the plant.

APPLICABLE SAFETY ANALYSES

The remote shutdown monitoring instrumentation is required to provide instrumentation at appropriate locations outside the control room with a capability to support maintaining the unit in a safe condition in MODE 3.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The criteria governing the design and the specific system requirements of the remote shutdown monitoring instrumentation are located in UFSAR, Appendix 3D.1.15 (Ref. 1).

The remote shutdown monitoring instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii). The control circuits and transfer switches required for a serious control room or cable spreading room fire are required to be maintained since they are used to meet 10 CFR 50 Appendix R requirements (Ref. 2).

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation necessary to support maintaining the unit in MODE 3 from a location other than the control room. The instrumentation required is listed in Table B 3.3.18-1.

The monitoring instrumentation are those required for:

- Core reactivity monitoring;
- RCS pressure monitoring;
- Decay heat removal via the AFW System and the MSSVs or SG atmospheric vent valves; and
- RCS inventory via makeup flow.

A Function of the remote shutdown monitoring instrumentation is OPERABLE if all channels needed to support the Function are OPERABLE.

The remote shutdown monitoring instrumentation covered by this LCO does not need to be energized to be considered OPERABLE. This LCO is intended to ensure the remote shutdown monitoring instrumentation will be OPERABLE if unit conditions require that the remote shutdown monitoring instrumentation be placed in operation.

The control circuits and transfer switches required by this LCO are those that are required for a serious control room or cable spreading room fire. The list of specific control circuits and transfer switches required has been developed based on a review of the Fire Hazard Analysis Report (FHAR) for the control room and cable spreading room fire areas. This list is maintained in the appropriate fire protection administrative procedures.

BASES

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the unit is already subcritical and is in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument Functions if the control room becomes inaccessible.

ACTIONS

Remote shutdown monitoring instrumentation is inoperable when each Function is not accomplished by at least one designated remote shutdown monitoring instrumentation channel that satisfies the OPERABILITY criteria for the channel's Function. These criteria are outlined in the LCO section of the Bases. Remote shutdown control circuit and transfer switch Functions required for a serious control room or cable spreading room fire are inoperable when a required Function's control cannot be shifted from the control room and transferred to and controlled at the remote location.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of the Specification may be entered independently for each Function. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes the control circuits and transfer switches for any required Function (i.e., required for a serious control room or cable spreading room fire).

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and takes into account the remaining OPERABLE channel and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met for remote shutdown monitoring instrumentation Functions, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within

BASES

ACTIONS

B.1 and B.2 (continued)

6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1

Required Action C.1 specifies immediate initiation of action described in Specification 5.6.7, "Remote Shutdown System Report," which requires a written report to be submitted to the NRC. This report discusses the evaluation into the cause of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since the control circuits and transfer switches are related to meeting 10 CFR 50, Appendix R requirements. The Completion Time of "Immediately" ensures the requirements of Specification 5.6.7 are initiated.

SURVEILLANCE REQUIREMENTS

SR 3.3.18.1

Performance of the CHANNEL CHECK once every 31 days for each required instrumentation channel that is normally energized ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If the channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.18.1 (continued)

are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency is based on unit operating experience, which demonstrates that channel failure is rare.

SR 3.3.18.2

CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. The test verifies that the channel responds to measured parameters within the necessary range and accuracy.

Whenever a resistance temperature detector (RTD) is replaced, the next required CHANNEL CALIBRATION of the RTD sensor is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

The Frequency is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift.

SR 3.3.18.3

SR 3.3.18.3 verifies each control circuit and transfer switch required for a serious control room fire or cable spreading room fire performs their intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel or remotely is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if a serious control room or cable spreading room fire occurs, the requirement of the Fire Protection Program can be met. The 24 month frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience demonstrates that these control circuits and transfer switches seldom fail to pass the Surveillance when performed at the 24 month Frequency.

BASES

REFERENCES

1. UFSAR, Appendix 3D.1.15, Criterion 19 – Control Room.
2. 10 CFR 50, Appendix R.

Table B 3.3.18-1 (page 1 of 1)
Remote Shutdown Monitoring Instrumentation

	FUNCTION	READOUT LOCATION	MEASUREMENT RANGE	REQUIRED NUMBER OF CHANNELS
1.	Reactor Trip Breaker Indication	Room 428, Low Voltage Switchgear Room – F Bus	Open - Close	1 (Trip Breaker A)
		Room 429, Low Voltage Switchgear Room – E Bus		1 (Trip Breaker B)
		Room 428, Low Voltage Switchgear Room – F Bus		1 (Trip Breaker C)
		Room 402, Electrical Penetration Room 1		1 (Trip Breaker D)
2.	Reactor Coolant Temperature – Hot Leg	Aux. Shutdown Panel	520°F – 620°F	1
3.	Reactor Coolant System Pressure	Aux. Shutdown Panel	0 psig – 3000 psig	1
4.	Pressurizer Level	Aux. Shutdown Panel	0 inches – 320 inches	1
5.	Steam Generator Outlet Steam Pressure	Aux. Shutdown Panel	0 psig – 1200 psig	1/steam generator
6.	Steam Generator Level Startup Range	Aux. Shutdown Panel	0 inches – 250 inches	1/steam generator
7.	Control Rod Position Switches	Control Rod Drive Control Cabinets, System Logic Cabinet #3	0%, 25%, 50%, 75%, and 100%	1/control rod

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 rate 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 ensure 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 corresponds to 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 corresponds to 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 DNBR 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 analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will meet the DNBR criterion for the current reload cycle (Ref. 2). This is the acceptance limit for the RCS DNBR parameters. Changes to the facility that 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)."

BASES

APPLICABLE SAFETY ANALYSES (continued)

The nominal core outlet pressure assumed in the safety analyses is 2200 psia. The minimum pressure specified in LCO 3.4.1 is the corresponding 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 582°F. The hot leg temperature of 610°F is to limit the range of allowable, steady state operation, consistent with the initial conditions assumed in the DNB-related accident analyses. 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 380,000 gpm. The minimum flow rate specified in LCO 3.4.1 is the equivalent minimum mass flow rate including a 2.5% uncertainty.

Analyses have been performed to establish the pressure, temperature, and flow rate 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 DNBR criterion, a corresponding maximum power limit is required (see Bases for LCO 3.4.4, "RCS Loops - MODES 1 and 2").

The RCS DNB limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables: RCS loop (hot leg) pressure, RCS hot leg temperature, and 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 (RCPs) running for the three RCPs operating condition.

The LCO numerical values for pressure, temperature, and flow rate are measured values and are given for the measurement location.

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 ensure that DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES the power level is low enough so that DNB is not a concern.

BASES

APPLICABILITY (continued)

The Note indicates the limit on RCS pressure may be exceeded during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% 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 < 100% RTP, increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNBR related parameters is provided in Safety Limit (SL) 2.1.1, "Reactor Core SLs." 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.

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. However, if the flow rate is below the LCO limit, the parameter must be restored to within limits or power must be reduced as required in Required Action B.1, to restore DNBR margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters 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.

B.1

If the Required Action A.1 is not met within the Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds.

The 6 hour Completion Time is reasonable, based on operating experience, to reduce power in an orderly manner in conjunction with even control of steam generator heat removal.

BASES

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 Frequency for 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 measurement location. The value used in the plant safety analysis is 2200 psia (nominal). 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.

A Note has been added to indicate the pressure limits are to be applied to the loop with two pumps in operation for the three pump operating condition.

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 Frequency for 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.

A Note has been added to indicate the temperature limits are to be applied to the loop with two pumps in operation for the three pump operating condition.

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 greater than or equal to the minimum required RCS flow rate. These minimum required measured flows include a flow rate uncertainty of 2.5%

The Frequency of 18 months is considered adequate for ensuring accurate RCS flow measurement instrumentation and has been shown by operating experience to be acceptable.

The Surveillance is modified by a Note that indicates the SR is not required to be performed until 24 hours after stable thermal conditions are established at ≥ 70% RTP. 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 at low power or in MODE 2 or below because at low power the ΔT across the core will be too small to provide valid results.

REFERENCES

1. UFSAR, Section 15.

2. UFSAR, Appendix 4B.

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; and b. Operation with reactor vessel above its minimum nil ductility reference temperature when the reactor is critical. The Reactor Protection System (RPS) 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.
APPLICABLE SAFETY ANALYSES	There are no accident analyses that dictate the minimum temperature for criticality. 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 582°F). Safety and operating analyses for lower temperatures have not been made. Compliance with the LCO ensures that the reactor will not be made or maintained critical at a temperature significantly less than the hot zero power (HZP) temperature, which is assumed in the safety analysis (Ref. 1). Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis. The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The purpose of the LCO is to prevent criticality much outside the minimum normal operating regime (532°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 $k_{eff} \geq 1.0$.

BASES

ACTIONS	A.1 With T_{avg} below 525°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ in 30 minutes. Rapid reactor shutdown can be readily and practically achieved in a 30 minute period. The Completion Time reflects the ability to perform this action and maintain the plant within the analyzed range. If T_{avg} can be restored within the 30 minute time period, shutdown is not required.
SURVEILLANCE REQUIREMENTS	SR 3.4.2.1 RCS loop average temperature is required to be verified at or above 525°F every 12 hours. The SR to verify RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.
REFERENCES	1. UFSAR, Section 15.2.1.

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 pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR lists the approved methodologies and contains P/T limit curves for heatup, cooldown, criticality, and inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature.

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 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. 2), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 2 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), Boiler and Pressure Vessel Code, Section III, Appendix G (Ref. 3).

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 Code, Section III, Appendix G; and Regulatory Guide 1.99 (Ref. 4).

BASES

BACKGROUND (continued)

Material toughness properties of the ferritic materials of the reactor vessel are determined in accordance with the NRC Standard Review Plan (Ref. 5), ASTM E 185 (Ref. 6), and additional reactor vessel requirements. These properties are then evaluated in accordance with Reference 3.

The actual shift in the nil ductility reference temperature (RT_{NDT}) of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 6) and Appendix H of 10 CFR 50 (Ref. 7). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 3.

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 span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

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

The calculation to generate the ISLH testing curve uses different safety factors (per Ref. 3) than the heatup and cooldown curves. The ISLH testing curve also extends to the RCS design pressure of 2500 psig.

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 nonductile 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.

BASES

BACKGROUND (continued)

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 8) 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 (DBA) 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 nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA analysis, 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.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The two elements of this LCO are:

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

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 ISLH 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 follows:

BASES

LCO (continued)

a. The severity of the departure from the allowable operating P/T 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 nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). 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 nonductile 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 can 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, "SLs," also provide operational restrictions for pressure and temperature and maximum pressure. MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

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 to within limits, an engineering evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed within 72 hours. Several methods may be used, including

BASES

ACTIONS

A.1 and A.2 (continued)

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 Code, Section XI, Appendix E (Ref. 8) 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 provided to accomplish the evaluation. The evaluation for a mild violation may be possible within this time, but more severe violations may require special, event specific stress analyses or inspections.

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

B.1 and B.2

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

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours, or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Actions B.1 and B.2. A favorable evaluation must be completed

BASES

ACTIONS

B.1 and B.2 (continued)

and documented before returning to operating pressure and temperature conditions. However, if the favorable evaluation is accomplished while reducing pressure and temperature conditions, a return to power operation may be considered without completing Required Actions B.1 and B.2.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified acceptable by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished within this time in a controlled manner.

In addition to restoring operation to within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analysis, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 8), may also be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone, per Required Action C.1, is insufficient because higher than analyzed stresses may have occurred and may have affected RCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature 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 permits 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.

This SR is modified by a Note that requires this SR to be performed only during system heatup, cooldown, and ISLH testing.

REFERENCES

1. Deleted (see CN# 11-040)
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. Regulatory Guide 1.99, Revision 2, May 1988.
5. NUREG-0800, Section 5.3.1, Rev. 1, July 1981.
6. ASTM E 185-82, July 1982.
7. 10 CFR 50, Appendix H.
8. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 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. Removing 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 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 < 80.6% 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 power levels. Specifying two RCS loops also provides the minimum necessary paths (two SGs) for heat removal.

The Reactor Protection System (RPS) Flux - ΔFlux - Flow (Table 3.3.1-1 Function 8) trip setpoint is automatically reduced when one pump is taken out of service; manual resetting is not necessary. However, the RPS High Flux - High Setpoint (Table 3.3.1-1 Function 1.a) trip setpoint must be manually reset.

BASES

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 that are of most importance to RCP operation are the four pump coastdown, single pump locked rotor, and single pump (broken shaft or coastdown) (Ref. 1).

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 and temperature SL (i.e., the departure from nucleate boiling ratio (DNBR) limit), assumes a maximum power level of 110% of 2817 MWT. This is the design overpower condition for four pump operation. The 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 that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

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 RPS Flux - ΔFlux - Flow Function. Overpower protection is also provided by the High Flux - High Setpoint Function, which must be manually reset for three pump operation. The maximum power level for three pump operation is < 80.6% 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 RCPs removed from service is not allowed by this Specification.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The purpose of this LCO is to require adequate forced flow for core heat removal. Flow is represented by the number of RCPs in operation in both RCS loops for removal of heat by the two SGs. 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 and certain RPS setpoints must be reset.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and has the potential to produce maximum THERMAL POWER. 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.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5,	"RCS Loops - MODE 3;"
LCO 3.4.6,	"RCS Loops - MODE 4;"
LCO 3.4.7,	"RCS Loops - MODE 5, Loops Filled;"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4,	"Decay Heat Removal (DHR) and Coolant Circulation - High Water Level"; and
LCO 3.9.5,	"Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

If only three RCPs are in operation and the RPS High Flux - High Setpoint trip setpoints have not been reset to within the Allowable Value provided in Table 3.3.1-1 Function 1.a for three RCP operation, the trip setpoints must be reset within 10 hours. This ensures the proper automatic overpower protection is provided by the RPS. The 10 hour Completion Time is reasonable based on the low probability of an accident occurring while operating outside the three RCP limit, the automatic protection provided by the RPS Flux - ΔFlux - Flow Function (which is automatically reset), and the number of steps required to complete the Required Action.

B.1

If any Required Action and associated Completion Time of Condition A is not met or if the requirements of the LCO are not met for reasons other than Condition A, the Required Action is to reduce power and bring the

BASES

ACTIONS

B.1 (continued)

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 conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours of the required number of loops in operation. Verification includes flow rate, temperature, or pump status 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.

REFERENCES

1. UFSAR, Section 15.2.5.

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 for heat removal during heatup and cooldown. The number of RCPs in operation will vary depending on operational needs, and if forced flow is used to meet the LCO, forced flow is provided 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 provide redundant paths for heat removal. Reactor coolant natural circulation is not normally used; however, the natural circulation flow rate is sufficient for core cooling and boron mixing. 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. When in natural circulation, it is preferable to remove heat using both SGs to avoid idle loop stagnation that might occur if only one SG were in service. One generator will provide adequate heat removal.
APPLICABLE SAFETY ANALYSES	No safety analyses related to loss of RCS loops are performed with initial conditions in MODE 3. Failure to provide heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent 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. RCS Loops - MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
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 normal way to transport heat, although natural circulation flow provides adequate removal and can be used to meet the

BASES

LCO (continued)

LCO requirements. A minimum of one running RCP meets the LCO requirement for one loop in operation, when forced flow is being used to meet the LCO requirements. Furthermore, the requirements for a loop in operation are also met when natural circulation is established.

If forced flow is used, an OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is OPERABLE. Alternately, if natural circulation is used, an OPERABLE RCS loop consists of an SG that is OPERABLE. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required. For forced flow, an OPERABLE steam generator requires ≥ 18 inches of secondary side water level above the lower tube sheet. For natural circulation flow, an OPERABLE steam generator requires ≥ 35 inches of secondary side water level above the lower tube sheet. In both cases, the steam generator maximum level must be maintained low enough such that the steam generator remains capable of decay heat removal by maintaining a steam flow path (i.e., ≤ 625 inches full range level).

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 to be OPERABLE but not in operation for redundant heat removal capability.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2;"
LCO 3.4.6, "RCS Loops - MODE 4;"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled;"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation - High Water Level"; and
LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

If one RCS loop is inoperable, redundancy for forced or natural circulation flow heat removal is 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 nonoperating 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.

BASES

ACTIONS (continued)

B.1

If restoration of an RCS loop as required in Required Action A.1 is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the plant may be placed on the DHR System. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to achieve cooldown and depressurization from the existing plant conditions and without challenging plant systems.

C.1 and C.2

If two RCS loops are inoperable or a required RCS loop is not in operation, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be immediately suspended. Action to restore one RCS loop to operation shall be immediately initiated and continued until one RCS loop is restored to OPERABLE status and to operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced or natural circulation flow is providing heat removal. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess RCS loop status. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side water level is either ≥ 18 inches above the lower tube sheet when the associated reactor coolant pump is operating (forced flow) or ≥ 35 inches above the lower

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

tube sheet if reactor coolant pumps are not operating (natural circulation flow). If the SG water level is not within the associated limit, it may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.5.3

Verification that each required RCP is 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 proper breaker alignment and power availability to each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. 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.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

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 generators (SGs) 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 forced coolant circulation. The number of pumps in operation can vary to suit the operational needs. If forced flow is used to meet the LCO, forced flow is provided from at least one RCP or one DHR pump for decay heat removal and transport. The flow provided by one RCP or one 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. Reactor coolant natural circulation is not normally used; however, the natural circulation flow rate is sufficient for core cooling and boron mixing. 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. When in natural circulation, it is preferable to remove heat using both SGs to avoid idle loop stagnation that might occur if only one SG were in service. One generator will provide adequate heat removal.
APPLICABLE SAFETY ANALYSES	No safety analyses related to loss of RCS loops are performed with initial condition in MODE 4. RCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
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. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS or DHR System loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced or natural circulation. The second loop that is required to be OPERABLE provides a redundant path for heat removal. The Note permits a limited period of operation without RCPs and DHR pumps. The RCPs and DHR pumps may be removed from operation for ≤ 1 hour provided certain requirements are met. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," is maintained when forced flow is stopped because an even concentration distribution

BASES

LCO (continued)

cannot be ensured. 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.

In MODE 4, it is sometimes necessary to stop all RCP and DHR pump forced circulation. This is permitted to change operation from one DHR loop to the other or perform the transition to and from the DHR System. The transition is between DHR loop operation and RCS loop operation (either forced or natural circulation flow). The time period is acceptable because, while natural circulation is not yet established, the conditions for natural circulation exist, (i.e., secondary side water level is within limits), the time period is short, the reactor coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

If forced flow is used, an OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is OPERABLE. Alternately, if natural circulation is used, an OPERABLE RCS loop consists of an SG that is OPERABLE. For forced flow, an OPERABLE steam generator requires ≥ 18 inches of secondary water level above the lower tube sheet. For natural circulation flow, an OPERABLE steam generator requires ≥ 35 inches of secondary water level above lower tube sheet. In both cases, the steam generator maximum level must be maintained low enough such that the steam generator remains capable of decay heat removal by maintaining a steam flow path (i.e., ≤ 625 inches full range level).

Similarly for the DHR System, an OPERABLE DHR loop is comprised of the OPERABLE DHR pump(s) capable of providing forced flow to the DHR cooler(s). DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. Furthermore, the two DHR loops share the same suction path through DH-11 and DH-12. Therefore, when both DHR loops are being used to meet the LCO requirements, control power is required to be removed from DH-11 and DH-12 valve operators, or manual valves DH-21 and DH-23 are required to be open. Additionally, since the DHR System is a manually operated system (i.e., it is not automatically actuated), each DHR loop is OPERABLE if it can be manually aligned (remote or local) to the decay heat removal mode.

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.

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2;"
LCO 3.4.5,	"RCS Loops - MODE 3;"
LCO 3.4.7,	"RCS Loops – MODE 5, Loops Filled;"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4,	"Decay Heat Removal (DHR) and Coolant Circulation – High Water Level"; and
LCO 3.9.5,	"Decay Heat Removal (DHR) and Coolant Circulation – Low Water Level."

ACTIONS

A.1

If only one required RCS loop or DHR 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 immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

A.2

If restoration is not accomplished and a DHR loop is OPERABLE, the unit must be brought to MODE 5 within the following 24 hours. Bringing the unit to 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 rather than MODE 4. The Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems.

This Required Action is modified by a Note which indicates that the unit must be placed in MODE 5 only if a DHR loop is OPERABLE. With no DHR loop OPERABLE, the unit is in a condition with only limited cooldown capabilities. Therefore, the actions are to be concentrated on the restoration of a DHR loop, rather than a cooldown of extended duration.

B.1 and B.2

If two required RCS or DHR loops are inoperable or a required loop is not in operation, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of

BASES

ACTIONS

B.1 and B.2 (continued)

LCO 3.1.1 must be suspended and action to restore one RCS or DHR loop to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to ensure continued safe operation. With coolant added without circulation, unmixed coolant could be introduced to the core, however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance requires verification every 12 hours of the required DHR or RCS loop in operation to ensure forced or natural circulation flow is providing decay heat removal. Verification includes flow rate, temperature, or pump status monitoring. If forced flow using the DHR loop is used to meet this requirement, the flow rate shall be ≥ 2800 gpm. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess RCS loop status. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side water level is either ≥ 18 inches above the lower tube sheet when the associated reactor coolant pump is operating (forced flow) or ≥ 35 inches above the lower tube sheet if reactor coolant pumps are not operating (natural circulation flow). If the SG water level is not within the associated limit, it may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.3

Verification that each required pump is OPERABLE ensures that an additional RCS or DHR 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 each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. The Frequency of 7 days is considered reasonable in view of other administrative controls and has been shown to be acceptable by operating experience.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

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 either to the steam generator (SG) secondary side coolant or the component cooling water via the decay heat removal (DHR) coolers. While the principal 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, 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. If forced flow is used to meet the LCO, forced flow is provided 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.

Reactor coolant natural circulation is not normally used; however, the natural circulation flow rate is sufficient for core cooling and boron mixing. 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. When in natural circulation, it is preferable to remove heat using both SGs to avoid idle loop stagnation that might occur if only one SG were in service. One generator will provide adequate heat removal.

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, an electrically driven feed pump is needed, because it is independent of steam. The Startup Feed Pump or the Motor Driven Feedwater pump can be used. If RCPs are available, the steam generator level need not be adjusted. If RCPs are not available, the water level must be adjusted for natural circulation. The high entry point in the generator is accessible from the Motor Driven Feedwater Pump so that natural circulation can be further stimulated, if needed. The SGs are primarily a backup to the DHR

BASES

BACKGROUND (continued)

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 for heat removal in MODE 4 is provided.

APPLICABLE SAFETY ANALYSES

No safety analyses related to loss of RCS loops are performed with initial conditions in MODE 5.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that two loops, RCS or DHR, be OPERABLE and one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS or DHR System loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced or natural circulation. The second loop that is required to be OPERABLE provides a redundant path for heat removal.

The LCO Note permits the DHR pump in the operating loop to be removed from operation for up to 1 hour. The circumstances for stopping both DHR loops are to be limited to situations where: (a) Pressure and temperature increases can be maintained well within the allowable pressure (P/T and low temperature overpressure protection) and 10°F subcooling limits; or (b) Alternate heat paths through the SGs are available.

The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, "SHUTDOWM MARGIN (SDM)," is maintained when DHR forced flow is stopped because an even concentration distribution cannot be ensured. 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 MODE 5, it is sometimes necessary to stop all RCP or DHR pump forced circulation. This is permitted to change operation from one DHR loop to the other or perform the transition to and from the DHR System. The transition is between DHR loop operation and RCS loop operation (either forced or natural circulation flow). The time period is acceptable because, while natural circulation is not yet established, the conditions for natural circulation exist (i.e., secondary side water level is within limits), the time period is short, the reactor coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

BASES

LCO (continued)

An OPERABLE RCS loop consists of an SG that is OPERABLE. An OPERABLE SG requires ≥ 35 inches of secondary side water level above the lower tube sheet. In addition, the steam generator maximum level must be maintained low enough such that the steam generator remains capable of heat removal by maintaining a steam flow path (i.e., ≤ 625 inches full range level). Furthermore, the SG must be capable of transferring heat from the reactor coolant at a controlled rate.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump and an OPERABLE DHR cooler. Furthermore, the two DHR loops share the same suction path through DH-11 and DH-12. Therefore, when both DHR loops are being used to meet the LCO requirements, control power is required to be removed from DH-11 and DH-12 valve operators, or manual valves DH-21 and DH-23 are required to be open.

DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. Additionally, since the DHR System is a manually operated system (i.e., it is not automatically actuated), each DHR loop is OPERABLE if it can be manually aligned (remote or local) to the decay heat removal mode.

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, "RCS Loops - MODES 1 and 2;"
LCO 3.4.5, "RCS Loops - MODE 3;"
LCO 3.4.6, "RCS Loops - MODE 4;"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation - High Water Level"; and
LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

If only one required RCS loop or DHR 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 immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

BASES

ACTIONS (continued)

B.1 and B.2

If no required loop is in operation, or no required loop is OPERABLE, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore a loop to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required RCS or DHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced or natural circulation flow is providing heat removal. If forced flow using the DHR loop is used to meet this requirement, the flow rate shall be ≥ 2800 gpm. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.7.2

Verifying the required SGs are OPERABLE by ensuring their secondary side water levels are ≥ 35 inches above the lower tube sheet ensures that redundant heat removal paths are available. 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.

SR 3.4.7.3

Verification that each required DHR pump is OPERABLE ensures that redundant paths for heat removal are available. The requirement also ensures that the additional loop can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation. If the secondary side water level is ≥ 35 inches above the lower tube sheet in

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.3 (continued)

both SGs, this Surveillance is not needed. Verification is performed by verifying proper breaker alignment and power available to each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. 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.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

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) coolers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid. Loops are not filled when the RCS draining is initiated (hot legs not completely filled). Additionally, the RCS inventory is further reduced to a water level within the horizontal portion of the hot leg, as might be the case for refueling or maintenance on the reactor coolant pumps or SGs. GL 88-17 (Ref. 1) expresses concerns for loss of decay heat removal for this operating condition. With water at this low level, the margin above the decay heat suction piping connection to the hot leg is small. The possibility of loss of level or inlet vortexing exists and if it were to occur, the operating DHR pump could become air bound and fail resulting in a loss of forced flow for heat removal. As a consequence the water in the core will heat up and could boil with the possibility of core uncovering due to boil off. Because the containment hatch may be open at this time, a pathway to the outside for fission product release exists if core damage were to occur. 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, to require that two paths be available to provide redundancy for heat removal.
APPLICABLE SAFETY ANALYSES	No safety analyses are performed with initial conditions in MODE 5 with loops not filled. The flow provided by one DHR pump is adequate for heat removal and for boron mixing. RCS Loops - MODE 5 (Loops Not Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The purpose of this LCO is to require that a minimum of two DHR loops be OPERABLE and that 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 provide redundancy for heat removal.

BASES

LCO (continued)

Note 1 permits the DHR pumps to be removed from operation for ≤ 15 minutes when switching from one loop to the other. The circumstances for stopping both DHR pumps are to be limited to situations where the outage time is short and temperature is maintained ≤ 190°F. The Note prohibits boron dilution with coolant at boron concentrations less than required to meet the SDM of LCO 3.1.1 and draining operations that could reduce the RCS water volume.

Note 2 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 capable of providing forced flow to an OPERABLE DHR cooler. Furthermore, the two DHR loops share the same suction path through DH-11 and DH-12. Therefore, when both DHR loops are being used to meet the LCO requirements, control power is required to be removed from DH-11 and DH-12 valve operators, or manual valves DH-21 and DH-23 are required to be open. DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. Additionally, since the DHR System is a manually operated system (i.e., it is not automatically actuated), each DHR loop is OPERABLE if it can be manually aligned (remote or local) to the decay heat removal mode.

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, "RCS Loops - MODES 1 and 2;"
LCO 3.4.5, "RCS Loops - MODE 3;"
LCO 3.4.6, "RCS Loops - MODE 4;"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled;"
LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation - High Water Level"; and
LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

If one required DHR loop is inoperable, redundancy for heat removal is lost. Required Action A.1 is to immediately initiate activities to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

BASES

ACTIONS (continued)

B.1 and B.2

If no required loop is OPERABLE or the required loop is not in operation, except as provided by Note 1 in the LCO, the Required Actions require immediate suspension of all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 and immediate initiation of action to restore one DHR loop to OPERABLE status and operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operations 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 every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. If the DHR loop is used to meet this requirement, the flow rate shall be ≥ 2800 gpm. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

SR 3.4.8.2

Verification that each required pump is OPERABLE ensures that redundancy for heat removal is provided. The requirement also ensures that an 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 each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. 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.

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES

1. Generic Letter 88-17, 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 level and the required heaters. Pressurizer safety valves and the pressurizer pilot operated relief valve (PORV) are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Pilot Operated Relief Valve (PORV)," 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 that could result in degraded ability for pressure control.

The maximum water 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 ensuring that pressure relief devices (PORVs or code 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 (SL) of 2750 psig or damage may occur to the PORVs or pressurizer code safety valves.

BASES

BACKGROUND (continued)

The essential 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 (SGs). 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. There are two essential heater banks, with each bank powered from a separate essential bus and each bank having a capacity of 126 kW.

A minimum required available capacity of 85 kW ensures 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 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. 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 noncondensible gases normally present.

Safety analyses presented in the UFSAR 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 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 an SL, 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 lower maximum level than assumed for the LOMFW event, have been made. The higher pressurizer level assumed for the LOMFW is the basis for the volume of reactor coolant

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 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 UFSAR accident analyses.

The maximum pressurizer water level limit satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). 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 ≤ 228 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 85 kW of essential pressurizer heaters OPERABLE. Since each essential bank has a capability of 126 kW, either essential bank can be used to meet the LCO requirement. 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 per bank 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.

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

BASES

APPLICABILITY (continued)

MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbations, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is the need to maintain the availability of pressurizer heaters capable of being powered from an emergency power supply. 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 MODE 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

With pressurizer water level in excess of the maximum limit, action must be taken to restore pressurizer operation to within the bounds assumed in the analysis. This is done by restoring the pressurizer water level to within the limit. The 1 hour Completion Time is considered to be a reasonable time for draining excess liquid.

B.1 and B.2

If the water level cannot be restored, reducing core power constrains heat input effects that drive pressurizer insurge that could result from an anticipated transient. Therefore, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant 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 conditions in an orderly manner and without challenging plant systems.

C.1

If the essential pressurizer heaters are inoperable, 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.

BASES

ACTIONS (continued)

D.1 and D.2

If essential pressurizer heater capability cannot be restored within the allowed Completion Time of Required Action C.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant 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 conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires 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 the indicated level. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess the 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 SR requires the power supplies are capable of producing the minimum power and the essential 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 24 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. NUREG-0737, November 1980.

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 (RPS), two valves are used to ensure that the Safety Limit (SL) of 2750 psig is not exceeded for analyzed transients during operation in MODES 1 and 2. Two safety valves are used for portions of MODE 3. For the remainder of MODE 3, MODES 4 and 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)."

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 into a separate tee opening directly into containment. Flow through the pressurizer safety valves generates acoustic levels or vibration that is detected by piezoelectric sensors on the discharge pipe. These sensors provide valve position indication (open/closed) in the control room.

The pressure limit is 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 (nominal operating temperature and pressure). 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.

APPLICABLE SAFETY ANALYSES

All accident analyses in the UFSAR 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 that could occur during a startup, rod withdrawal, ejected rod, loss of main feedwater, or main feedwater line break accident. The

BASES

APPLICABLE SAFETY ANALYSES (continued)

startup accident establishes the minimum safety valve capacity. The startup accident is assumed to occur from a subcritical condition. 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 ensure that the accident analysis and design basis calculations remain valid.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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 SL, to maintain accident analysis assumptions. The pressure limit is based on the + 1% tolerance requirements 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 if a transient were to occur.

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 prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, 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 is conservatively included, although the listed accidents may not require both safety valves for protection.

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

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.

BASES

ACTIONS (continued)

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 brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power conditions 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME OM Code (Ref. 2), which provides the activities and the Frequency necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is + 1% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance in accordance with Reference 1.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Pilot Operated Relief Valve (PORV)

BASES

BACKGROUND

The pressurizer is equipped with three devices for pressure relief functions: two American Society of Mechanical Engineers (ASME) pressurizer safety valves that are safety grade components and one PORV that is not a safety grade device. The PORV is an electromatic 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 the essential buses, which are powered from either the offsite power sources or the emergency power sources. Power supplies for the PORV are separate from those for the block valve. Power supply requirements are defined in NUREG-0737, Paragraph II, G.1 (Ref. 1).

The PORV setpoint (≥ 2435 psig) 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 that 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.

The PORV is also set such that it will open before the pressurizer safety valves are opened. However, it should not open on any anticipated transients. BAW-1890, September 1985 (Ref. 3) identified that the turbine trip from full power would cause the largest overpressure transient. The Reference 3 analysis demonstrated that with an RPS RC High Pressure trip setpoint of 2355 psig, the resulting overshoot in RCS

BASES

BACKGROUND (continued)

pressure would be limited to 50 psi. Consequently, the minimum PORV setpoint needs to accommodate both the RCS pressure overshoot and the RPS instrument string error of 30 psi.

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. 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 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 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.

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.

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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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). UFSAR 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 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires the PORV and its associated 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.

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 that 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 surges become much less significant.

ACTIONS

A.1 and A.2

With the PORV inoperable, the PORV must be restored or the flow path isolated within 1 hour. The block valve must be closed and power must be removed from the block valve to reduce the potential of inadvertent depressurization that would occur if the PORV failed open.

BASES

ACTIONS (continued)

B.1 and B.2

If the block valve is inoperable, it must be restored to OPERABLE status within 1 hour. 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 close the block valve and remove power within 1 hour rendering the PORV isolated. The 1 hour Completion Times are 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 adequate protection against RCS depressurization.

C.1 and C.2

If the Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power conditions 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 conditions 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 of 92 days is the ASME Code (Ref. 4). Block valve cycling, as stated in the Note, is not required to be performed when it is closed for isolation; cycling could increase the hazard of an existing degraded flow path.

SR 3.4.11.2

PORV cycling demonstrates its function. Any combination of indications (e.g., acoustic, system response) may be used to confirm a complete cycle of the PORV. The Frequency of 24 months is based on a typical refueling cycle and industry accepted practice.

BASES

REFERENCES

1. NUREG-0737, Paragraph II, G.1, November 1980.
2. NRC IE Bulletin 79-05B, April 21, 1979.
3. BAW-1890, September 1985.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

BASES

BACKGROUND

LTOP controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) 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, "RCS Pressure and Temperature (P/T) Limits," provides the allowable combinations for operational pressure and temperature during cooldown, shutdown, and heatup to keep from violating the Reference 1 limits.

The reactor vessel material is less tough at reduced temperatures than at normal operating temperature. Also, as vessel neutron irradiation accumulates, the material becomes less resistant to pressure stress at low temperatures (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, heatup, or any anticipated operational occurrence must be controlled to not violate LCO 3.4.3. Exceeding these limits could lead to brittle fracture of the reactor vessel. LCO 3.4.3 presents requirements for administrative control of RCS pressure and temperature to prevent exceeding the P/T limits.

This LCO provides RCS overpressure protection in the applicable MODES by ensuring an adequate pressure relief capacity through the Decay Heat Removal (DHR) System relief valve.

The DHR System relief valve provides overpressure protection for the RCS during low temperature operations. RCS and DHR Systems are monitored for temperature and pressure. Maintaining the relief setpoint within the limits of the LCO ensures the Reference 1 limits will be met in any event in the LTOP analysis.

If system pressure exceeds the lift setpoint of the DHR System relief valve, it will open. As the relief valve opens, coolant is released and pressure decreases. When the relief valve reset is reached, below the LTOP pressure limit, the relief valve closes.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel can be adequately protected against overpressurization transients during shutdown. In MODES 1 and 2, and portions of MODE 3, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. For the remaining portions of MODE 3, overpressure protection is

BASES

APPLICABLE SAFETY ANALYSES (continued)

provided by operating procedures. At nominally 280°F and below, overpressure prevention falls to the OPERABLE DHR System relief valve.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as vessel material toughness decreases due to neutron embrittlement. Each time the P/T limit curves are revised, the LTOP will be re-evaluated to ensure that its functional requirements can still be met with the DHR System relief valve and operating procedures.

Transients that are capable of overpressurizing the RCS have been identified and evaluated. These transients relate to either mass input or heat input: actuating the High Pressure Injection (HPI) System, discharging the Core Flooding Tanks (CFTs), energizing the pressurizer heaters, failing the makeup control valve open, losing decay heat removal, and starting a reactor coolant pump (RCP).

The DHR System relief valve (DH-4849), which is in the suction line to the decay heat pumps, has been sized to pass 1800 gpm at the nominal set pressure of 320 psig. The flow rate is based on the maximum developed runout flow (900 gpm per pump) with both HPI pumps running simultaneously. This flow rate is considered to cause the worst credible pressure transient. The opening of a CFT isolation valve was not considered because power is removed from the valve once it is closed upon plant cooldown and depressurization. Other postulated occurrences, makeup control valve failing open, loss of DHR System cooling, all pressurizer heaters energizing, do not produce a pressure excursion as severe as that produced by the two HPI pumps. Although the pressurizer, by procedure, cannot be solid, for the purpose of analysis it was considered to go solid during the transient. The DHR System relief valve is a Seismic Class I Nuclear Class 2 bellows type of safety-relief valve. It should be noted that the postulation of both HPI pumps starting during DHR System operation is made only for the purpose of sizing the DHR System relief valve. The possibility of this event occurring due to either a single operator error or a single spurious signal is precluded by the design of the Safety Features Actuation System.

The Reference 3 analyses demonstrate the DHR System relief valve can maintain RCS pressure below limits.

The DHR System relief valve is placed in service before RCS temperature is reduced below 280°F. Above this temperature, the pressurizer safety valves and operating procedures provide the reactor

BASES

APPLICABLE SAFETY ANALYSES (continued)

vessel pressure protection. The vessel materials were assumed to have a neutron irradiation accumulation exceeding 32 effective full power years (EFPYs) of operation.

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.

As required by License Condition 2.C(3)(d), prior to operation beyond 32 Effective Full Power Years, a reanalysis and proposed modifications, as necessary, to ensure continued means of protection for LTOP events will be provided to the NRC. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to embrittlement induced by neutron irradiation. Revised P/T limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens.

LCO

For low temperature overpressure protection, Davis-Besse relies on the four-inch DHR System relief valve (DH-4849) with a lift setpoint ≤ 330 psig. This relief valve is located on the DHR System suction line from the RCS. The RCS to DHR System isolation valves (DH-11 and DH-12) must be open and control power removed from the valve operators for the DHR System relief valve to be OPERABLE. Control power can be removed either in the control room or at the motor control center (by removing fuses, opening breakers, or racking breakers out).

APPLICABILITY

This LCO is applicable in MODES 4 and 5, and in MODE 6 when the reactor vessel head is on. The Applicability is established by fracture mechanics analyses. The pressurizer safety valves provide overpressure protection to meet LCO 3.4.3 P/T limits in MODES 1, 2, and 3. With the vessel head off, overpressurization is not possible.

LCO 3.4.3 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.

ACTIONS

A.1 and A.2

With the DHR System relief valve inoperable due to one or both RCS to DHR System isolation valves closed, the overpressure protection flow path is isolated. The flow path must be restored by opening the RCS to DHR System isolation bypass valves (DH-21 and DH-23), within 1 hour.

BASES

ACTIONS

A.1 and A.2 (continued)

After opening, the RCS to DHR System isolation bypass valves must be verified open every 24 hours.

The 1 hour Completion Time reflects the importance of the action and provides time for a timely opening of the RCS to DHR System isolation bypass valves. To ensure they remain in the open position, the positions of the RCS to DHR System isolation bypass valves are required to be verified every 24 hours. RCS to DHR System isolation bypass valves are manual valves and do not have remote position indication.

B.1

With control power available to one or both of the RCS to DHR System isolation valves, the overpressure protection flow path could be inadvertently isolated. The control power must be removed from the valves within 1 hour to ensure the valves will remain open during system operation.

The 1 hour Completion Time reflects the importance of the action and provides time for a timely removal of control power.

C.1

If the DHR System relief valve is inoperable for reasons other than the relief flow path (Condition A or B), the DHR System relief valve must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time is acceptable due to the low probability of an overpressure event.

D.1, D.2, D.3, and D.4

If any Required Action and Completion Time of Condition A, B, or C is not met, other compensatory actions must be taken to minimize the probability and consequences of an LTOP event. Without an OPERABLE relief path for overpressure protection, the RCS water addition capabilities must be limited. Within 1 hour both HPI pumps must be disabled (e.g., by opening motor supply breakers), and within 8 hours the makeup pump suction automatic transfer to the borated water storage tank on low makeup tank level must be disabled. Makeup tank level must be verified to be ≤ 73 inches within 8 hours to minimize volume. Furthermore, without an overpressure relief path, RCS pressure and pressurizer level

BASES

ACTIONS

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

must be verified to be in the Acceptable Region of Figure 3.4.12-1 or 3.4.12-2 (depending on the MODE) within 8 hours to ensure an overpressure condition cannot occur. These Figures do not include instrument error uncertainties.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

Verification of the flow path from the RCS to the DHR System relief valve is required every 24 hours. This verification is performed by checking RCS to DHR System isolation valves in the open position with control power removed from the valve operator. This Surveillance ensures the overpressure relief flow path is aligned and remains aligned. Removal of control power ensures the flow path is not inadvertently closed.

The Frequency is adequate based on operating experience. Manual operation is required to close the isolation valves or energize control power. Valve operations are administratively controlled by procedure. In this configuration the isolation valves will not inadvertently close.

SR 3.4.12.2

Verification of the DHR System relief valve lift setpoint must be performed to ensure LTOP requirements can be met. Overpressure protection of the RCS is ensured by the DHR System relief valve, which relieves pressure and prevents the RCS from exceeding the Pressure/Temperature Limits.

The DHR System relief valve setpoint is verified in accordance with the Inservice Testing (IST) Program for proper operation and correct lift setting of ≤ 330 psig. This lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure. The IST Program specifies the testing and frequency, as directed by ASME Code.

REFERENCES

1. 10 CFR 50, Appendix G.

2. Generic Letter 88-11.

3. UFSAR, Section 9.3.5.

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.

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.

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. Although not committed to Regulatory Guide 1.45 (Ref. 2), it 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 is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary 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 reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to 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). However, the ability to monitor leakage provides advance warning to permit plant shutdown before a LOCA occurs. This advantage has been shown by "leak before break" studies.

BASES

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 that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gallon per minute or increases to 1 gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) 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 leakage contaminates the secondary fluid.

The UFSAR (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 safety analysis assumption is relatively inconsequential.

The safety analysis for the MSLB accident assumes the entire 1 gpm primary to secondary LEAKAGE is through the affected generator as an initial condition. The dose consequences resulting from the MSLB accident are well within the limits defined in 10 CFR 100.

RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

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. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

BASES

LCO (continued)

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 unidentified 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 (RCP) seal return flow (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 Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

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.

BASES

APPLICABILITY (continued)

LCO 3.4.14, "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

If unidentified LEAKAGE or identified LEAKAGE are in excess of the LCO limits, the LEAKAGE must be reduced to within limits 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 primary to secondary LEAKAGE is not within limit, or if unidentified or identified 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 must be brought to 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 allowed are reasonable, based on operating experience, to reach the required conditions from full power conditions 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 ensures 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 an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable temperature, power level, and pressurizer level). The accuracy of the results will be impacted if any

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

measured parameter used to calculate the RCS LEAKAGE is not in a steady state condition.

The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

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

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable power level (± 1%).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.2 (continued)

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 15.
4. NEI 97-06, "Steam Generator Program Guidelines."
5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 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), discuss reactor coolant pressure boundary valves, which are normally closed valves in series within the reactor coolant pressure boundary that separate the high pressure RCS from an attached low pressure system. The 1975 Reactor Safety Study, WASH-1400, (Ref. 4) identified intersystem loss of coolant accidents (LOCAs) as a significant contributor to the risk of core melt. The study considered designs containing two in-series check valves and two check valves in series with a motor operated valve that isolated the high pressure RCS from the low pressure safety injection system. The scenario considered is a failure of the two check valves leading to overpressurization and rupture of the low pressure injection piping which results in a LOCA that bypasses containment. A letter was issued (Ref. 5) by the NRC requiring plants to describe the PIV configuration of the plant. On April 20, 1981, the NRC issued an Order modifying the Davis-Besse Technical Specifications to include testing requirements on PIVs and to specify the PIVs to be tested (Ref. 6). During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through 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 a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leakage 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 leaktight.

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 that could degrade the ability for low pressure injection.

BASES

BACKGROUND (continued)

PIVs are provided to isolate the RCS from the Decay Heat Removal (DHR) System. The PIVs are CF-30, CF-31, DH-76, and DH-77.

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.

Two motor operated valves (which are not PIVs) are included in series in the suction piping of the DHR System to isolate the high pressure RCS from the low pressure piping of the DHR System when the RCS pressure is above the design pressure of the DHR System piping and components. Ensuring the DHR System interlock function that closes the valves and prevents the valves from being opened is OPERABLE ensures that RCS pressure will not pressurize the DHR System beyond its test pressure.

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 reactor coolant pressure boundary (RCPB), and the subsequent pressurization of the DHR System downstream of the PIVs from the RCS. Because the DHR System is not designed to handle normal RCS pressures, overpressurization failure of the DHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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.

The LCO PIV leakage limit is ≤ 5.0 gpm. However, when the current measured rate is > 1.0 gpm, the current measured rate shall not exceed the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate (5.0 gpm) by 50%.

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) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases,

BASES

LCO (continued)

the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

Ensuring the DHR System interlock function that closes the valves and prevents the valves from being opened is OPERABLE ensures that RCS pressure will not pressurize the DHR System beyond its test pressure.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, the valves in the DHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the DHR mode of operation and the DHR System interlock function is not required to meet the requirements of this LCO.

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

The ACTIONS are modified by two Notes. Note 1 is added to provide clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

If the leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by two valves. Required Actions A.1 and A.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 RCS pressure boundary or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hours allows the actions and restricts the operation with leaking isolation valves.

BASES

ACTIONS

A.1 and A.2 (continued)

Required Action A.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.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 5 within 36 hours. This Required Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

The inoperability of the DHR System interlock function renders the DHR suction isolation valves incapable of isolating in response to a high pressure condition and preventing inadvertent opening of the valves at RCS pressures in excess of the DHR systems design pressure. If the DHR interlock is inoperable, operation may continue as long as the DHR suction line is isolated by two closed and deactivated automatic valves within 4 hours. This action accomplishes the purpose of the interlock function.

Alternately, if the RCS pressure is < 328 psig, isolating the associated DHR penetration is not required. In this case, the DHR System interlock function must be restored to OPERABLE status prior to increasing RCS pressure ≥ 328 psig. Since RCS pressure is below the setpoint, there is no need to isolate the associated penetration.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

SR 3.4.14.1 is the performance of the CHANNEL CHECK of the decay heat isolation valve interlock channel that is common to the Safety Features Actuation System (SFAS) instrumentation. The check provides

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.14.2

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 or A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The RCS PIVleakage limit is ≤ 5.0 gpm. However, RCS PIV leakage is also limited when the current measured rate is > 1.0 gpm, such that the current measured rate shall not exceed the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and 5.0 gpm by 50%. Leakage testing requires a stable pressure condition. Valves CF-30 and CF-31 will be tested with the RCS pressure > 1200 psig and valves DH-76 and DH-77 will be tested at > 575 psig (i.e., the normal core flooding tank pressure). Minimum differential test pressure across each valve shall be > 150 psid. Additionally, to satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

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 leakage tested, one valve may have failed completely and not detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 24 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 24 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 7), and is based on the need to perform such surveillances under conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the plant at power.

The leakage limit is to be performed at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.2 (continued)

pressures. Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complimentary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months.

SR 3.4.14.3 and SR 3.4.14.4

Verifying that the DHR interlocks are OPERABLE ensures that RCS pressure will not pressurize the DHR system beyond 430 psig, the pressure at which this section of DHR piping was tested. The interlock setpoint that prevents the valves from being opened is set so the actual RCS pressure must be < 328 psig at the RCS pressure instrumentation tap to open the valves. This setpoint allows DH-11 and DH-12 to be opened by the operator prior to the point where net positive suction pressure is lost to the reactor coolant pumps. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance was performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

These SRs are modified by Notes allowing the DHR System interlock function to be disabled when using the DHR System suction relief valve for cold overpressure protection in accordance with LCO 3.4.12. This allowance is necessary since opening and removing control power to the DHR System isolation valves (as required by LCO 3.4.12) disables the interlock.

SR 3.4.14.5

SR 3.4.14.5 requires the performance of a CHANNEL CALIBRATION of the DHR System interlock channels (both the channel common to SFAS instrumentation and the channel not common to SFAS instrumentation). The calibration verifies the accuracy of the instrument string. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 55a(c).

3. 10 CFR 50, Appendix A, Section V, GDC 55.

4. NUREG-75/014, Appendix V, October 1975.

5. Letter from D.G. Eisenhut, NRC, to all LWR Licenses, LWR Primary Coolant System Pressure Isolation Valves, February 23, 1980.

6. Letter from J.F. Stoltz, NRC, to R.P. Crouse, Order for Modification of License Concerning Primary Coolant System Pressure Isolation Valves, April 20, 1981.

7. ASME Code for Operation and Maintenance of Nuclear Power Plants.

8. 10 CFR 50.55a(g).

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. Although not committed to Regulatory Guide 1.45, Revision 0, (Ref. 2), it 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. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

The containment sump used to collect unidentified LEAKAGE is instrumented to allow detecting increases above the normal flow rates.

The reactor coolant contains radioactivity that, when released to the containment, may be detected by radiation monitoring instrumentation. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE. Other indications may be used to detect an increase in unidentified LEAKAGE; however, they are not required to be OPERABLE by this LCO. 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 humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE.

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. Humidity monitors are not required for this LCO.

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

BASES

BACKGROUND (continued)

pressure measurements is 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. Temperature and pressure monitors are not required by this LCO.

The above-mentioned LEAKAGE detection methods or systems differ in sensitivity and response time. Some of these systems could serve as early alarm systems signaling the operators that closer examination of other detection systems is necessary to determine the extent of any corrective action that may be required.

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 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 provides quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the unit and the public.

Refer to the Bases of LCO 3.4.13, "RCS Operational LEAKAGE," for further information regarding RCS LEAKAGE.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified LEAKAGE are detected in time to allow actions to place the plant in a safe condition when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires two instruments to be OPERABLE.

The containment normal sump is used to collect unidentified LEAKAGE. The LCO requirements apply to the total amount of unidentified LEAKAGE collected in this sump. The monitors associated with the containment normal sump detect level or flow rate. The monitors are instrumented to detect when there is an increase above the normal value by 1 gpm. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the containment normal sump and it may take longer than one hour to detect a 1 gpm increase in unidentified LEAKAGE, depending on the

BASES

LCO (continued)

origin and magnitude of the LEAKAGE. This sensitivity is acceptable for containment normal sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by the gaseous or particulate containment atmosphere radioactivity monitor. Only one of the two detectors is required to be OPERABLE. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE, but have recognized limitations. 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. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in unidentified LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Ref. 3).

The LCO requirements are satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor (both the level and flow portions), in combination with a particulate or gaseous radioactivity monitor, provides an acceptable minimum.

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 pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation is much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the containment sump monitor inoperable (i.e., either level or flow or both), no other form of sampling can provide the equivalent information.

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

BASES

ACTIONS

A.1 and A.2 (continued)

SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, and pressurizer level). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the containment 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 water inventory balance required by Required Action A.1.

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

With required gaseous or 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 a water 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. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, and pressurizer level). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leak detection is available.

C.1 and C.2

With the containment sump monitor inoperable, the only means of detecting LEAKAGE is the required containment atmosphere radiation monitor. A Note clarifies that this Condition is applicable when the only OPERABLE monitor is the containment atmosphere gaseous radioactivity monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the containment atmosphere

BASES

ACTIONS

C.1 and C.2 (continued)

must be taken to provide alternate periodic information. The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

D.1 and D.2

If a Required Action of Condition A, B, or C cannot be met within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With both 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

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. 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.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a CHANNEL FUNCTIONAL TEST of the required containment atmosphere radioactivity monitor. 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.3 and SR 3.4.15.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the required 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 or 24 months, as applicable, considers channel reliability and, operating experience has proven this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.

2. Regulatory Guide 1.45, Revision 0, “REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS,” May 1973.

3. USAR Section 5.2.4.

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 limits. 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 an SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits (Ref. 1). 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 guideline limits following an SGTR accident. The SGTR safety analysis (Ref. 2) assumes a specific activity value equivalent to 1% failed fuel 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 following a SGTR.

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 that could affect RCS specific activity as they relate to the acceptance limits. The assumed RCS specific activity in the SGTR analysis bounds the LCO limit for RCS specific activity.

The rise in pressure in the ruptured SG causes radioactively contaminated steam to discharge to the atmosphere through 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the Reference 1 dose guideline limits. 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 an SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

RCS Specific Activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the gross 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 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 such that the RCS specific activity is greater than the analysis assumptions, may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 530°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross 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 < 530°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 main steam safety valves.

BASES

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to verify the limits of Figure 3.4.16-1 are not exceeded. An isotopic analysis of a reactor coolant sample must be performed for at least I-131, I-133, and I-135. 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 limits within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

If a Required Action and associated Completion Time of Condition A are not met, if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1, or if the gross specific activity is not within limit, the reactor must be brought to MODE 3 with RCS average temperature < 530°F within 6 hours. The Completion Time of 6 hours is required to get to MODE 3 below 530°F without challenging reactor emergency systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once per 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with RCS average temperature at least 530°F. The 7 day Frequency considers the unlikelihood of a gross fuel failure during that time period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance requires the verification that the reactor coolant DOSE EQUIVALENT I-131 specific activity is within limit. This Surveillance is accomplished by performing an isotopic analysis of a reactor coolant sample. This Surveillance is performed in MODE 1 only to ensure the 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 specific activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change of ≥ 15% RTP 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.

SR 3.4.16.3

SR 3.4.16.3 requires radiochemical analysis for $\bar{E}$ determination every 184 days 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 specific 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 $\bar{E}$ does not change rapidly.

This SR has been modified by a Note that states sampling is not required to be performed until 31 days after a minimum of 2 EFPD and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. 10 CFR 100.11.

2. UFSAR, Section 15.4.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops – MODES 1 and 2," LCO 3.4.5, "RCS Loops – MODE 3," LCO 3.4.6, "RCS Loops – MODE 4," and LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.8, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.8. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via main steam safety valves.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute. DOSE EQUIVALENT I-131 is assumed to be equivalent to 1% failed fuel in the accident analysis. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.8, and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

BASES

LCO (continued)

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm per SG. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one

BASES

LCO (continued)

SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

BASES

ACTIONS

A.1 and A.2 (continued)

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1 (continued)

specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.8 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.8 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. 10 CFR 50 Appendix A, GDC 19.

3. 10 CFR 100.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Core Flooding 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 large break LOCA, which follows immediately, reactor coolant inventory has vacated the core through steam flashing and ejection through the break. 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 can be 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.

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.

BASES

BACKGROUND (continued)

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.

During this event, the CFTs discharge to the RCS as soon as RCS pressure decreases below CFT pressure. In the LOCA analysis, HPI and LPI are not credited until 40 seconds after actuation of the associated Safety Features Actuation System (SFAS) signal. 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 SFAS 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 for the ECCS established by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

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

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Maximum hydrogen generation from a zirconium water reaction of ≤ 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 along with failure of a CFT, 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.

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 analytical limits for CFT volume are 7480 gallons (12.412 ft) and 8078 gallons (13.588 ft). Values of ≥ 12.6 ft and ≤ 13.3 ft are specified. These values allow for instrument inaccuracies in maintaining the analytical limits.

The minimum nitrogen cover pressure requirement of 580 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 620 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. These values allow for instrument inaccuracies in maintaining the analytical limits. The values specified for volume and pressure are based in the most accurate available indications

BASES

APPLICABLE SAFETY ANALYSES (continued)

(i.e., computer points). Additional allowances for instrument inaccuracies are included in the implementing procedures when less accurate indications are used. 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.

The minimum boron requirement of 2600 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, 50% of the 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 in the event of a large break LOCA.

The CFTs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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 in the event of 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 and power removed, and the limits established in the SR for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 800 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 > 800 psig. At ≤ 800 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.

BASES

APPLICABILITY (continued)

In MODE 3 with RCS pressure ≤ 800 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.

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.

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 will be 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.

C.1 and C.2

If the CFT cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and RCS pressure reduced to ≤ 800 psig within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

D.1

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

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 that ensure that a mispositioned isolation valve is unlikely.

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.

SR 3.5.1.4

Surveillance once every 31 days is reasonable to verify that the CFT boron concentration is within the required limits, 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 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. This is consistent with the recommendations of NUREG-1366 (Ref. 3).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.5

Verification every 31 days that power is removed from each CFT isolation valve operator (by locking the breaker in the open position) 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 and the postulated LOCA is a rupture of the redundant CFT inlet piping, CFT capability would be rendered inoperable. The rupture would render the tank with the open valve inoperable, and a closed valve on the other CFT would likewise render it inoperable. This would cause a loss of function for the CFTs. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that the power is removed.

REFERENCES

1. UFSAR, Section 6.3.
2. 10 CFR 50.46.
3. NUREG-1366, December 1992.

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:

a. Loss of coolant accident (LOCA);

b. Rod ejection accident (REA);

c. Steam generator tube rupture (SGTR); and

d. Main steam line break (MSLB).

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.

The HPI pumps are capable of discharging to the RCS at an RCS pressure of approximately 1600 psig. The LPI pumps are capable of discharging to the RCS at an RCS pressure of approximately 200 psig. 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.

BASES

BACKGROUND (continued)

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 uses the discharge of LPI pump 1 through a line that bypasses the RCS to Decay Heat Removal (DHR) System suction line and allows reverse flow into the DHR System drop line. The other flow path is through the pressurizer auxiliary spray line from HPI pump 2 in piggy-back with LPI pump 2.

The HPI subsystem also functions to supply borated water to the reactor core following increased heat removal events, such as large MSLBs.

During a large break LOCA, RCS pressure will decrease to < 200 psia in < 20 seconds. The ECCS is actuated upon receipt of an Safety Features Actuation System (SFAS) signal. The actuation of Engineered Safety Features (ESF) loads is accomplished in a programmed time sequence. If offsite power is available, the ESF loads start immediately. If offsite power is not available, the essential buses shed normal operating loads and are connected to the emergency diesel generators. ESF loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive core flooding tanks (CFTs) and the BWST covered in LCO 3.5.1, "Core Flooding Tanks (CFTs)," and LCO 3.5.4, "Borated Water Storage Tank (BWST)," provide the cooling water necessary to meet 10 CFR 50.46 (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. 1), 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LCO also helps ensure 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. 2). 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 MSLB analyses also credit the HPI pump but are not limiting in their design.

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 boil off 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 subcritical.

In the LOCA analyses, HPI and LPI are not credited until 40 seconds after actuation of the associated SFAS 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.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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, the decay heat removal cooler (for the LPI subsystem only), instruments, and controls to

BASES

LCO (continued)

ensure an OPERABLE flow path capable of taking suction from the BWST upon an SFAS signal and manually transferring suction to the containment sump.

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.

As Noted, the BWST outlet and containment emergency sump valves may be considered OPERABLE when the associated valve motors are de-energized, provided the valves are not otherwise inoperable. This allowance is necessary since the motor operators are normally de-energized in MODES 1, 2, 3, and 4 to prevent spurious closing of the BWST outlet valves and opening of the containment emergency sump valves in the event of a control room fire (i.e., to meet the 10 CFR 50 Appendix R requirements). This allowance was originally approved by the NRC in References 6 and 7.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS train OPERABILITY requirements for the limiting Design Basis Accident, a 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 is less dependent on power. MODES 2 and 3 requirements are bounded by the MODE 1 analysis.

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, "Decay Heat Removal (DHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

BASES

ACTIONS

A.1

With one LPI subsystem inoperable, action must be taken to restore it to OPERABLE status within 7 days. In this condition, the remaining OPERABLE ECCS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure to the remaining LPI subsystem could result in loss of ECCS function. The 7 day Completion Time is reasonable to perform corrective maintenance on the inoperable LPI subsystem. The 7 day Completion Time is based on the findings of the deterministic and probabilistic analysis in Reference 3. Reference 3 concluded that extending the Completion Time to 7 days for an inoperable LPI subsystem improves plant operational flexibility while simultaneously reducing overall plant risk. This is because the risks incurred by having the LPI subsystem unavailable for a longer time at power will be substantially offset by the benefits associated with avoiding unnecessary plant transitions and by reducing risk during plant shutdown operations.

B.1

With one or more trains inoperable and at least 100% of the injection flow equivalent to a single OPERABLE ECCS train available, components inoperable for reasons other than Condition A 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 train is inoperable if it is not capable of delivering the design flow to the RCS.

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. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

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.

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable components cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 conditions in an orderly manner and without challenging plant systems.

D.1

Condition B is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the facility is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

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 nonaccident 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 is appropriate because the valves are operated under administrative control, and an inoperable valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.2

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code (Ref. 5). This type of testing may be accomplished by measuring the pump's developed head at only one point of the pump's characteristic curve. This verifies both that the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 (continued)

measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant accident analysis. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.3

With the exception of systems in operation, the ECCS pumps are normally in a standby, nonoperating mode. As such, the flow path piping has the potential to develop voids and pockets of entrained gases. This SR requires maintaining the piping from the ECCS pumps to the RCS full of water, by venting the ECCS pump casings and discharge piping high points, to ensure 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 noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SFAS signal or during shutdown cooling. The 24 month Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping, the existence of procedural controls governing system operation, and the fact that some venting point are not accessible during normal operation. The second Frequency is required to ensure the ECCS subsystem is refilled after draining prior to declaring the ECCS subsystem OPERABLE.

SR 3.5.2.4 and SR 3.5.2.5

These SRs demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SFAS signal and that each ECCS pump starts on receipt of an actual or simulated SFAS signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 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 SFAS testing, and equipment performance is monitored as part of the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.6

This Surveillance verifies the position of each mechanical stop for valves DH-14A and DH-14B is correct to ensure that proper ECCS flows will be maintained in the event of a LOCA. Maintenance of proper flow resistance and pressure drop in the piping system to each injection point is necessary to prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration, provide the proper flow split between injection points in accordance with the assumptions used in the LOCA analyses, and provide an acceptable level of total ECCS flow to all injection points equal to or above that assumed in the LOCA analyses. The 24 month Frequency is justified by the same reasons as those stated for SR 3.5.2.4 and SR 3.5.2.5.

SR 3.5.2.7

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. In addition, the screen components include the vertical strainers. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, on the need to preserve access to the location, and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation and has been confirmed by operating experience.

SR 3.5.2.8

This Surveillance verifies that the BWST outlet valve (HV-DH7A and HV-DH7B) automatically closes after the operator manually pushes the control switch to open the containment emergency sump valve (HV-DH9A and HV-DH9B), and the containment emergency sump valve opens, following receipt of a Borated Water Storage Tank Level – Low Low signal (i.e., Table 3.3.5-1, Function 5). This SR also verifies each valve's closure or opening time, as applicable, is $\leq$ 75 seconds. The closure and opening times are measured from when the operator pushes the control switch for the associated containment emergency sump valve until the valve is either fully open or closed, as applicable. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

BASES

REFERENCES

1. 10 CFR 50.46.

2. UFSAR, Section 6.3.

3. BAW-2295-A, Revision 1, Justification for Extension of Allowed Outage Time for Low Pressure Injection and Reactor Building Spray System.

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

5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

6. NRC letter from J.B. Hopkins (NRC) to D.C. Shelton, Administrative Changes to Technical Specifications Bases, dated October 21, 1992.

7. NRC letter from J.B. Hopkins to L.F. Storz, Issuance of Amendment 182, dated December 16, 1993.

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, "ECCS - Operating," is applicable to these Bases, with the following modifications. In MODE 4, the required ECCS subsystem consists of a single low pressure injection (LPI) subsystem. The ECCS flow path consists of piping, valves, heat exchanger (i.e., decay heat cooler), and a pump, 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. Only one ECCS subsystem is required for MODE 4. This requirement dictates that single failures are not considered during this MODE. The ECCS subsystem satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	In MODE 4, one of the two independent (and redundant) ECCS LPI subsystems is required to ensure sufficient ECCS flow is available to the core following a DBA. In MODE 4, an ECCS subsystem consists of an LPI subsystem. An LPI subsystem includes an LPI pump, a decay heat cooler, and the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST and manually transferring suction to the containment emergency 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 LPI pump and the respective supply headers, to each of the core flood nozzles. In the long term, this flow path may be switched to take its supply from the containment emergency sump. As Noted, the BWST outlet and containment emergency sump valves may be considered OPERABLE when the associated valve motors are de-energized, provided the valves are not otherwise inoperable. This allowance is necessary since the motor operators are normally de-energized in MODES 1, 2, 3, and 4 to prevent spurious closing of the

BASES

LCO (continued)

BWST outlet valves and opening of the containment emergency sump valves in the event of a control room fire (i.e., to meet 10 CFR 50 Appendix R requirements). This allowance was originally approved by the NRC in References 6 and 7.

APPLICABILITY

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

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

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 Note prohibits the application of LCO 3.0.4.b to the inoperable ECCS LPI subsystem when entering MODE 4 from MODE 5. There is an increased risk associated with entering MODE 4 from MODE 5 with the LPI subsystem inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components. The provision should not be applied in this circumstance.

A.1

If no LPI subsystem 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 immediately, which would initiate action to 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 subsystem operating with suction from the RCS. If no LPI subsystem is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generator(s). 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 is provided.

BASES

ACTIONS

A.1 (continued)

With both LPI pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the LPI subsystems operating in the decay heat removal 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

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 canal 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 manually 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).

This LCO ensures that:

a. The BWST contains sufficient borated water to support the ECCS during the injection phase;

b. 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

c. 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.

Improper boron concentrations could result in a reduction of SDM or 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 containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown. The design basis

BASES

APPLICABLE SAFETY ANALYSES (continued)

transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of the Bases of LCO 3.5.2, "ECCS - Operating," and LCO 3.6.6, "Containment Spray and Air Cooling Systems." These analyses are used to assess changes to the BWST in order to evaluate their effects in relation to the acceptance limits.

The limits on volume of ≥ 500,100 gallons and ≤ 550,000 gallons are based on several factors. Per NUREG-0800, Section 6.3 (Ref. 1), 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, because this gives the operator adequate time to prepare for switchover to containment sump recirculation. The minimum required volume provides a volume in excess of 20 minutes of full flow of all ECCS pumps.

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 UFSAR (Ref. 2), 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 does not take credit for more than the minimum volume of usable water (i.e., water above the discharge line location) from the BWST.

The third factor is that the volume of water in the BWST must be within a range that will ensure 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 usable volume required to be in the BWST; a certain amount of water is unusable because of tank discharge line location.

The 2600 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 50% of the control rods remain withdrawn from the core.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 2800 ppm maximum limit for boron concentration in the BWST is also 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.

Boron concentrations in the BWST in excess of the limit could reduce the time available to initiate boric acid precipitation control measures, which are taken to avoid reaching the solubility limit.

The 35°F lower limit on the temperature of the solution in the BWST is assumed for the containment vessel vacuum breaker sizing. This temperature also helps prevent boron precipitation. The 90°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, with the exception of the BWST minimum volume of 500,100. This value is instrument error compensated to ensure the required minimum volume is available for injection into the core and containment. The remaining values are either instrument uncertainty adjusted in surveillance procedures or include sufficient analysis margin such that the instrument errors would be bounded by the margin.

The BWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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 an adequate level exists in the containment sump to support ECCS and containment

BASES

LCO (continued)

spray pump operation in the recirculation mode. To be considered OPERABLE, the BWST must meet the limits for water volume, boron concentration, and temperature established in the SRs.

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 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

With either the BWST boron concentration or borated water temperature not within limits, the condition must be corrected within 8 hours. In this condition, neither the ECCS nor the Containment Spray System can perform its design functions. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which these systems are not required. The 8 hour limit to restore the temperature or boron concentration to within limits was developed considering the time required to change boron concentration or temperature and assuming that the contents of the tank are still available for injection.

B.1

With the BWST inoperable for reasons other than Condition A (e.g., water volume), the BWST must be restored to OPERABLE status within 1 hour. In this condition, neither the ECCS nor the Containment Spray System can perform its design functions. Therefore, prompt action must be taken to restore the BWST to OPERABLE status or to place the plant in a MODE in which the BWST is not required. The allowed Completion Time of 1 hour to restore the BWST to OPERABLE status is based on this condition simultaneously affecting multiple redundant trains.

BASES

ACTIONS (continued)

C.1 and C.2

If the BWST cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

Verification every 24 hours that the BWST water temperature is within the specified temperature band ensures that the boron will not precipitate; the containment vessel vacuum breaker sizing assumption is met; and the fluid temperature entering the reactor vessel will not be hotter than assumed in the LOCA analysis. The 24 hour Frequency is sufficient 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 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.

SR 3.5.4.2

Verification every 7 days that the BWST available volume is within the required range ensures that a sufficient initial supply is available for injection and to support continued ECCS pump operation on recirculation. The limits on water volume reflect the available volume since a portion of the contained volume of the BWST is not available because of the tank discharge configuration. Since the BWST volume is normally stable and provided with a low level alarm, a 7 day Frequency has been shown to be appropriate through operating experience.

SR 3.5.4.3

Verification every 7 days that the boron concentration of the BWST fluid is 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.

BASES

REFERENCES

1. NUREG-0800, Section 6.3.

2. UFSAR, Section 6.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment vessel, including all its penetrations, is a low leakage steel structure designed to withstand a postulated loss-of-coolant accident and to confine a postulated release of radioactive material. The containment vessel is a cylindrical steel pressure vessel with hemispherical dome and ellipsoidal bottom. It is completely enclosed by a reinforced concrete shield building having a cylindrical shape with a shallow dome roof. An annular space is provided between the wall of the containment vessel and the shield building, and clearance is also provided between the containment vessel and the dome of the shield building.

The shield building is a concrete structure surrounding the containment vessel. It is designed to provide biological shielding during normal operation and from hypothetical accident conditions. The building provides a means for collection and filtration of fission product leakage from the containment vessel following a hypothetical accident through the Station Emergency Ventilation System, an engineered safety feature designed for that purpose. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

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

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

   1. Capable of being closed by an OPERABLE automatic containment isolation system; or

   2. Closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves;"

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks;"

c. The equipment hatch is closed; and

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES

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

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA, a main steam line break, and a control rod assembly (CRA) ejection accident (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or CRA ejection accident. In the DBA analyses, it is assumed that the containment is OPERABLE 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 0.50% of containment air weight per day (Ref. 3). This leakage rate, used in the evaluation of offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable leakage rate at the calculated maximum peak containment pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.50% per day in the safety analysis at P_a = 38 psig (Ref. 3).

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

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to < 1.0 L_a, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and containment purge and exhaust valves with resilient seals and secondary containment bypass leakage paths (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of < 1.0 L_a.

BASES

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, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed under Containment Closure Control.

ACTIONS

A.1

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

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. The shield building exterior visual examinations may be performed during either power operation or during a maintenance or refueling outage. The visual examinations of the shield building interior and the steel containment vessel are performed during maintenance or refueling outages since this is the only time the steel containment vessel is fully accessible.

Failure to meet air lock, containment purge and exhaust valve with resilient seals, and secondary containment bypass leakage paths leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for Option B for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of < 1.0 L_a. At < 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis.

SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. UFSAR, Section 15.4.
3. UFSAR, Section 6.2.1.2.2.

B 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, approximately 10 ft in diameter for the personnel air lock and approximately 6 ft in diameter for the emergency air lock, with a door at each end. 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 local indication of door position.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA), a main steam line break, and a control rod assembly ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE 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 0.50% of containment air weight per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated maximum peak containment pressure (P_a) following a design basis LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. L_a is 0.50% per day and P_a is 38 psig, resulting from the limiting design basis LOCA.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As a part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate 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 (personnel and emergency) 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. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

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 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 are addressed under Containment Closure Control.

ACTIONS

The ACTIONS 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 for most repairs. If the inner door is inoperable, then it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE 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 ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

BASES

ACTIONS (continued)

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

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

With one air lock door inoperable in one or more containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock.

This ensures that 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, which requires containment be restored to OPERABLE status within 1 hour.

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

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

BASES

ACTIONS

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

The Required Actions have been modified by two Notes. Note 1 clarifies that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

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

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

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

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

BASES

ACTIONS (continued)

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

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected 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, which requires that containment be restored to OPERABLE status within 1 hour.

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

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of 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. The periodic testing requirements verify that the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable, since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock 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 support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the air lock.

BASES

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. UFSAR, Section 15.4.
3. UFSAR, Section 6.2.1.2.2.

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 or power operated remote manual) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close 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 or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Containment vessel isolation occurs upon receipt of an actuation signal from the Safety Features Actuation System (SFAS). Closure of the specific containment isolation valves is dependent upon the SFAS Incident Level. SFAS Incident Level 1 (either a high containment pressure or a low Reactor Coolant System (RCS) pressure) isolates the Containment Purge and Exhaust System and Sample System valves in order to prevent radiation from leaving the vessel through non-essential lines. SFAS Incident Level 2 (low RCS pressure or a high containment pressure) initiates high pressure injection and closes the Containment Isolation System 1 valves. SFAS Incident Level 3 (low-low RCS pressure or high containment pressure) closes Containment Isolation System 2 valves. SFAS Incident Level 4 (high-high containment pressure), indicating a major loss of coolant accident, closes Containment Isolation System 3 valves. 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).

OPERABILITY of the containment isolation valves (and blind flanges) supports containment OPERABILITY during accident conditions.

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the

BASES

BACKGROUND (continued)

safety analysis. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analysis will be maintained.

The Containment Purge and Exhaust System is designed to provide clean fresh air to the containment vessel or to the shield building and penetration rooms. Containment vessel may be purged in MODES 5 and 6. The shield building and mechanical penetration rooms may be purged at any time. The Containment Purge and Exhaust System includes 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. 1) to permit access within a reasonable time. The containment purge supply and exhaust lines each contain two isolation valves, one located inside containment and one located outside containment.

Failure of the containment purge and exhaust valves to close following a design basis event would cause a significant increase in the radioactive release 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 0.50% of containment air weight per day (L_a) (Ref. 2). Because of their large size, the 48 inch containment purge and exhaust valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 48 inch containment purge and exhaust valves are maintained closed with control power removed (SR 3.6.3.1) in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. 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), a main steam line break, and a control rod assembly ejection accident (Ref. 3). 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 paths to the environment through containment isolation valves (including

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment purge and exhaust valves) are minimized. The safety analysis assumes that the 48 inch purge valves are closed at event initiation.

The DBA analysis assumes that, within 60 seconds after 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, emergency 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 unit safety analyses was considered in the original design of the containment purge and exhaust valves. Two valves in a series on each containment purge and exhaust line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The containment purge and exhaust valves are air operated spring closed. The valves fail closed on a loss of power or instrument air.

The containment purge and exhaust valves may be unable to close in the environment following a LOCA. Therefore, each of the containment purge and exhaust valves is required to remain closed with control power removed during MODES 1, 2, 3, and 4. In this case, the single-failure criterion remains applicable to the containment purge and exhaust valves because of failure in the control circuit associated with each valve. Again, the Containment Purge and Exhaust System valve design prevents a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valve safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 48 inch containment purge and exhaust valves must be maintained closed with control power removed. The valves covered by this LCO are listed along with their associated stroke times in the UFSAR (Ref. 4). However, the main steam isolation valves and main feedwater stop valves are not covered by this LCO. Requirements for these valves

BASES

LCO (continued)

are provided in LCO 3.7.2, "Main Steam Isolation Valves (MSIVs)," and LCO 3.7.3, "Main Feedwater Stop Valves (MFSVs), Main Feedwater Control Valves (MFCVs), and associated Startup Feedwater Control Valves (SFCVs)." This allowance is documented in the NRC Safety Evaluation for Amendment 279, the ITS conversion amendment.

Power operated remote manual valves (i.e. non-automatic power operated valves) are considered OPERABLE when the valve motors are energized and the valves are capable of being closed (electrical or air operated). These active valves are listed in Reference 4.

The normally closed isolation valves are considered OPERABLE when manual valves are closed, check valves have flow through the valve secured, blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are listed in Reference 4.

Containment purge and exhaust valves with resilient seals and secondary containment bypass leakage paths must meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

This LCO provides assurance that the containment isolation valves will perform their designated safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

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 in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed under Containment Closure Control.

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 48 inch containment purge and exhaust valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge and exhaust line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow paths containing these valves may not be opened under administrative controls.

BASES

ACTIONS (continued)

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, except for containment purge and exhaust valve leakage or secondary containment bypass leakage paths not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 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 supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths 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 and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those isolation devices

BASES

ACTIONS

A.1 and A.2 (continued)

outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating this Condition is only applicable to those penetration flow paths with two or more containment isolation valves. For penetration flow paths with only one containment isolation valve, Condition C provides appropriate actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows the devices to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is small.

B.1

With two or more containment isolation valves in one or more penetration flow paths inoperable, except for containment purge and exhaust valve leakage or secondary containment bypass leakage paths not within limit, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic

BASES

ACTIONS

B.1 (continued)

verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative controls and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two or more containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable, considering: the relative stability of the system (hence, reliability) to act as a penetration isolation boundary, since it does not communicate with the containment atmosphere or reactor coolant pressure boundary (for certain valves in Type III penetrations); the small pipe diameter of the penetration (hence, reliability) (for certain valves in Type II, III and IV penetrations); that the valves isolate Engineered Safety Features Systems that normally operate following an accident (for most valves in Type IV penetrations); and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment 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 flow path is isolated is appropriate considering the fact that the valves are operated under administrative controls and the probability of their misalignment is low.

BASES

ACTIONS

C.1 and C.2 (continued)

If containment air cooling (CAC) service water (SW) piping is ever isolated due to a breach of the piping in containment, that system is no longer acting as a penetration boundary. Because the CAC SW piping does not connect with either the reactor coolant system or the containment atmosphere, and post LOCA operation is for the system to be in service, CAC SW penetrations are not subject to testing under the Containment Leakage Rate Testing Program. Therefore, breached CAC SW piping in containment that is isolated would represent unquantifiable secondary containment bypass leakage for the associated CAC SW outlet penetration.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these devices, once verified to be in the proper position, is small.

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

In the event one or more containment purge or exhaust valves in one or more penetration flow paths are not within the purge and exhaust valve leakage limits, purge and exhaust valve leakage must be restored to within limits or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.5. The specified Completion Time is reasonable, considering that one containment purge and exhaust valve remains closed so that a gross breach of containment does not exist.

BASES

ACTIONS

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

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the containment purge and exhaust valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.5 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

E.1

With the combined secondary containment bypass leakage (SR 3.6.3.7) not within limit, the assumptions of the safety analyses are not met. Therefore, the leakage must be restored to within limit. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be

BASES

ACTIONS (continued)

E.1 (continued)

exceeded by use of one closed and deactivated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time for secondary bypass leakage not within limit is reasonable considering the time required to restore the leakage by isolating the penetration(s) and the relative importance of secondary containment bypass leakage to the overall containment function.

F.1 and F.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 48 inch containment purge and exhaust valve is required to be verified closed with control power removed 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 or exhaust valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the closed position with control power removed during MODES 1, 2, 3, and 4. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator.

SR 3.6.3.2

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2 (continued)

outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means 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 containment isolation valves, once they have been verified to be in the proper position, is low.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate, since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3 (continued)

isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated 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 Testing Program.

SR 3.6.3.5

For containment purge and exhaust valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. The test is performed by pressurizing the piping section, including one valve inside and one valve outside containment, to a pressure ≥ 20 psig. The leakage limit for each containment purge or exhaust penetration is ≤ 0.15 L_a. 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 prior to entering MODE 2 from MODE 3 each time the plant has been in any combination of MODE 3, 4, 5, or 6 for > 72 hours, if not performed in the previous 184 days has been established.

Additionally, if a valve is opened in MODE 1, 2, 3, or 4, this SR must be performed within 72 hours after closing the valve. Alternately, if a valve is opened in other than MODE 1, 2, 3, or 4, this SR must be performed prior to entering MODE 4 from MODE 5. These two additional Frequencies were chosen recognizing that cycling a valve could introduce additional seal degradation. Thus, these additional Frequencies are a prudent measure after a valve has been opened.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

This SR ensures that the combined leakage rate of all secondary containment bypass leakage paths is less than or equal to the specified leakage rate. This provides assurance that the assumptions in the safety analysis are met. The leakage rate acceptance criteria is in accordance with the Containment Leakage Rate Testing Program requirements, unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. Bypass leakage is considered part of L_a.

REFERENCES

1. 10 CFR 20.
2. UFSAR, Section 3.8.2.1.2.
3. UFSAR, Section 15.4.
4. UFSAR, Table 6.2-23.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	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 main steam line break (MSLB). 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 coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.
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 pressure, are the LOCA and MSLB, which are analyzed using computer pressure transients. The worst-case LOCA generates larger mass and energy release than the worst-case MSLB. Thus, the LOCA event bounds the MSLB event from the containment peak pressure standpoint (Ref. 1). The initial pressure condition used in the containment analysis was 1 psig. This resulted in a maximum peak pressure from a LOCA of 38 psig. The LCO limit of +25 inches water gauge (0.9 psig) ensures that, in the event of an accident, the design pressure of 40 psig for containment is not exceeded. In addition, the building is designed for an internal pressure equal to 3 psig above external pressure during a tornado. The containment is also designed for an internal pressure equal to 0.67 psig below external pressure, to withstand the resultant pressure drop from an accidental actuation of the Containment Spray System, with the containment vacuum breakers limiting the pressure transient. The LCO limit of -14 inches water gauge (-0.5 psig) ensures that operation within the design limit of -0.67 psig is maintained (Ref. 2). For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling Systems during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 3).

Containment Pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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, along with the containment vacuum breakers, ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System. Containment pressure is measured relative to the shield building pressure.

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 ensure initial conditions assumed in the accident analysis are maintained, the LCO is applicable 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 and 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, containment pressure must be restored to within these limits 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 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on

BASES

ACTIONS

B.1 and B.2 (continued)

operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that 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 during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

REFERENCES

1. UFSAR, Section 3.11.2.

2. UFSAR, Section 3.8.2.1.4.

3. 10 CFR 50, Appendix K.

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). 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 main steam line break (MSLB). The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. This LCO ensures that initial conditions assumed in the analysis of a DBA are not violated during unit operations. The total amount of energy to be removed by the Containment Air Cooling System during post accident conditions is dependent upon the energy released to the containment due to the event as well as the initial containment temperature and pressure. The higher the initial temperature, the higher the resultant peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident 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. Average air temperature is also used to establish the containment environmental qualification operating envelope. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analysis for containment. Several accidents (primarily LOCA and MSLB) result in a marked increase in containment temperature and pressure due to energy release within the containment. Of these, the MSLB results in the greatest sustained increase in containment temperature. By maintaining containment air temperature at less than the initial temperature assumed in the MSLB analysis, the containment design condition will not be exceeded. Containment Air Temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the containment structural temperature is maintained below its design temperature and that required safety related equipment will continue to perform its function.
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 MODE 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. This 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. B.1 and B.2 If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.5.1 Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated, using the inlet temperature to the operating containment air coolers (i.e., 1-1, 1-2, and 1-3). 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.

BASES

REFERENCES None.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Air Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Air Cooling (CAC) Systems provide 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 within limits. The Containment Spray and Containment Air Cooling Systems are designed to meet the requirements of UFSAR, Appendices 3D.1.34, 3D.1.35, 3D.1.36, 3D.1.37, 3D.1.38, and 3D.1.39 (Ref. 1).

The Containment Spray System and Containment Air Cooling System are Engineered Safety Features (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 Air Cooling System provide redundant containment heat removal operation. The Containment Spray System and Containment Air Cooling System provide redundant methods to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate, independent trains of equal capacity, each capable of meeting the design basis. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate essential 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 emergency sump.

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 and to reduce the concentration of fission products in the containment atmosphere 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.

BASES

BACKGROUND (continued)

In the event of a loss of coolant accident (LOCA), high containment pressure or low Reactor Coolant System pressure will actuate a Safety Features Actuation System (SFAS) level 2 trip to open the spray isolation valves. High-high containment pressure will actuate an SFAS level 4 signal to start the two containment spray pumps. During switchover of spray suction from the BWST to the containment emergency sump, the containment spray isolation valves are automatically throttled to a position that ensures there is adequate net positive suction head (NPSH) available for the containment spray pump. 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 Air Cooling System

The Containment Air Cooling System consists of three containment cooling trains that draw air from the containment atmosphere and discharge into a common supply plenum. Each cooling train is equipped with cooling coils, and an axial flow fan driven by a two speed electric motor. The Containment Air Cooling System ductwork required to remain intact following a loss-of-cooling accident consists of the portions of the discharge air ductwork that extend between the containment air cooler fans and the backdraft dampers, upstream of the supply plenum.

During normal operation, two containment air cooling trains are required to operate. The third unit is on standby and isolated from the operating units by means of the backdraft dampers. The swing unit can be manually placed to either the Train 1 or Train 2 power train to operate in case one of the operating units fails. Upon receipt of an emergency signal, the operating cooling fans running at high speed will automatically trip. The two cooling unit fans connected to the essential buses will automatically restart and run at slow speed, provided normal or emergency power is available.

In post accident operation following an actuation signal, the Containment Air Cooling System fans are designed to start automatically in slow speed if they are not already running. If they are running at high (normal) speed, control power is interrupted causing the fans to trip out of normal high speed. At the same time a slow speed start is initiated. A 5 second time delay is initiated to permit fan coastdown prior to being restarted in slow speed. The fans are operated at the slow speed during accident conditions to prevent motor overload from the higher density atmosphere.

BASES

APPLICABLE SAFETY ANALYSES

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

The analysis and evaluation show that, under the worst-case scenario, the highest peak containment pressure is 38 psig (experienced during a LOCA). The analysis shows that the peak containment vapor temperature is 364.9°F (experienced during a MSLB). (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5, "Containment Air Temperature," for additional discussion.) The LOCA peak pressure analyses and evaluations assume a power level of 3025 MWt, one containment spray train and one containment cooling train operating, and initial (pre-accident) conditions of 120°F and 1 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

An analysis of the containment vessel negative pressure transient due to inadvertent operation of one train of the Containment Spray System has been performed for various spray water temperatures. A conservative spray flow rate of 2100 gpm has been assumed to account for pump run-out with the containment vessel at ambient pressure. The transient pressure response of the containment vessel was analyzed for the following two cases: 35°F spray water with eight vacuum breakers operational, and; 60°F spray water with six vacuum breakers operational. The analysis demonstrated that the number of vacuum breakers required to prevent the containment vessel from exceeding its external pressure loading design value (0.67 psig) is sensitive to spray (BWST) water temperature. For BWST water temperatures below 60°F a minimum of eight operational vacuum breakers out of the ten installed would protect the containment vessel from external pressure loadings that exceed the design value. When BWST water temperature exceeds 60°F only six operational vacuum breakers would be needed.

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 achieve full flow through the containment spray nozzles. The Containment Spray System total response time of 80 seconds includes emergency diesel generator (EDG) startup (for loss of offsite power), block loading of equipment, containment spray pump startup, and spray line filling (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment air cooling train performance for post accident conditions is given in Reference 3. The result of the analysis is that each containment air cooling train can provide 50% 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 Air Cooling System actuation from the containment analysis is based on a response time associated with exceeding the containment pressure high setpoint to achieve full Containment Air Cooling System air and safety grade cooling water flow. The Containment Air Cooling System total response time of 300 seconds includes signal delay, EDG startup (for loss of offsite power), and service water pump startup times (Ref. 3).

The Containment Spray System and the Containment Air Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one containment air cooling train and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits. Additionally, one containment spray train is required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and two independent containment air 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 train typically includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon a Safety Features Actuation System signal and manually transferring suction to the containment emergency sump.

Each containment air cooling train includes cooling coils, dampers, an axial flow fan driven by a two speed electrical motor, instruments, and controls to ensure an OPERABLE flow path.

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 air cooling trains.

BASES

APPLICABILITY (continued)

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and the Containment Air Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, action must be taken to restore it to OPERABLE status within 7 days. In this condition, the remaining OPERABLE containment spray train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure to the remaining containment spray train could result in loss of spray function. The 7 day Completion Time is reasonable to perform corrective maintenance on the inoperable containment spray train. The 7 day Completion Time is based on the findings of the deterministic and probabilistic analysis in Reference 5. Reference 5 concluded that extending the Completion Time to 7 days for an inoperable containment spray train improves plant operational flexibility while simultaneously reducing overall plant risk. This is because the risks incurred by having the containment spray train unavailable for a longer time at power will be substantially offset by the benefits associated with avoiding unnecessary plant transitions and by reducing risk during plant shutdown operations.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time to attempt restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

BASES

ACTIONS (continued)

C.1

With one of the required containment air cooling trains inoperable, the inoperable containment air cooling train must be restored to OPERABLE status within 7 days. The remaining OPERABLE containment spray and air cooling trains in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. 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 Air Cooling System and the low probability of a DBA occurring during this period.

D.1 and D.2

With one containment spray and one required containment air cooling train inoperable, either one containment spray train or one of the required containment air cooling trains must be restored to OPERABLE status within 72 hours. The remaining OPERABLE containment spray and air cooling trains in this degraded condition provide iodine removal capabilities and are capable of providing at least 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 Air Cooling System, the iodine removal function of the Containment Spray System, and the low probability of a DBA occurring during this period.

E.1

With two of the required containment air cooling trains inoperable, one of the required containment air cooling trains must be restored to OPERABLE status within 72 hours. The remaining OPERABLE containment spray trains in this degraded condition (both containment spray trains are OPERABLE or else Condition G is entered) provide iodine removal capabilities and are capable of providing at least 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 Air Cooling System and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

F.1 and F.2

If the Required Actions and associated Completion Times of Condition C, D, or E are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

With two containment spray trains or any combination of three or more required containment spray and containment air cooling trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray 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. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

Initiating from the control room (if not already operating) and operating each required containment air 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3

Verifying that each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 6). 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 tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.6.4

This SR requires verification that each required containment air cooling train actuates on slow speed upon receipt of an actual or simulated SFAS actuation signal. The 18 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience.

SR 3.6.6.5

Verifying that each required containment air cooling train provides a service water cooling flow rate of ≥ 1150 gpm to each cooling unit provides assurance that the flow rate assumed in the safety analyses will be achieved (Ref. 3). The 24 month Frequency is based on the need to perform this Surveillance during a plant outage.

SR 3.6.6.6 and SR 3.6.6.7

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated SFAS actuation signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.6 and SR 3.6.6.7 (continued)

at power. Operating experience has shown that these components usually pass the Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.6.8

Surveillance Requirement SR 3.6.6.8 requires verification that each nozzle is unobstructed following maintenance that could cause nozzle blockage. Normal plant operation and maintenance activities are not expected to trigger performance of this surveillance requirement. However, activities such as an inadvertent spray actuation that causes fluid flow through the nozzles, or a loss of foreign material control when working within the respective system boundary may require surveillance performance. An evaluation, based on the specific situation, will determine the appropriate method (low pressure air or smoke flow test) to verify no nozzle obstruction.

REFERENCES

1. UFSAR, Appendices 3D.1.34, Criterion 38 – Containment Heat Removal; 3D.1.35, Criterion 39 – Inspection of Containment Heat Removal System; 3D.1.36, Criterion 40 – Testing of Containment Heat Removal System; 3D.1.37, Criterion 41 – Containment Atmosphere Cleanup; 3D.1.38, Criterion 42 – Inspection of Containment Atmosphere Cleanup Systems, and 3D.1.39, Criterion 43 – Testing of Containment Atmosphere Cleanup Systems.

2. UFSAR, Section 6.2.2.

3. UFSAR, Section 6.2.

4. UFSAR, Figure 6.2-26.

5. BAW-2295-A, Revision 1, Justification for Extension of Allowed Outage Time for Low Pressure Injection and Reactor Building Spray Systems.

6. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Trisodium Phosphate Dodecahydrate (TSP) Storage

BASES

BACKGROUND

The TSP storage baskets are a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

The Containment Spray System and TSP storage baskets perform no function during normal operations. In the event of an accident such as a loss of coolant accident (LOCA), however, the containment emergency sump will flood to a level above the TSP storage baskets. This level of water will dissolve the TSP in the storage baskets and mix with the containment emergency sump water.

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.

The function of the TSP contained in baskets located in the containment normal sump and on the 565 ft elevation of containment adjacent to the normal sump, is to neutralize the acidity of the post-LOCA borated water mixture during containment emergency sump recirculation. The borated water storage tank (BWST) borated water has a nominal pH of approximately 5.0. A pH of 7.0 is assumed for the containment emergency sump for iodine retention and removal post-LOCA by the containment spray system.

The TSP storage baskets provide a spray solution with a pH between 7.0 and 8.0 within 4 hours of the start of recirculation (Ref. 1). This alkalinity was established not only to 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 also considers the environmental qualification of equipment in containment that may be subjected to the spray.

APPLICABLE SAFETY ANALYSES

The containment TSP storage baskets are 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 following the accident. The analysis assumes that most of the containment volume is covered by the spray.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the evaluation of the worst-case LOCA, the safety analysis assumed that an alkaline containment spray effectively reduced the airborne iodine.

The TSP Storage satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The TSP storage baskets are necessary to reduce the release of radioactive material to the environment in the event of a DBA. The volume contained in the TSP storage baskets (≥ 290 ft^3) is sufficient to raise the average spray solution pH to a level conducive to iodine removal. This volume includes a 40 ft^3 margin. The average spray solution pH is ≥ 7.0. 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.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Containment Spray System. The TSP storage baskets assist in reducing the iodine fission product inventory prior to release to the environment.

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 TSP storage baskets are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With the TSP storage baskets not within the required limit, the TSP storage baskets must be restored to within the limit within 72 hours. 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 this into account along with the low probability of the worst-case DBA occurring during this period.

B.1 and B.2

If the TSP storage baskets cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant

BASES

ACTIONS

B.1 and B.2 (continued)

systems. The extended interval to reach MODE 5 allows additional time for restoration of the TSP storage baskets 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

To reduce the potential for post-LOCA iodine re-evolution from the water in the containment emergency sump, the containment spray must be an alkaline solution. Since the BWST contents are normally acidic, the TSP storage baskets must provide sufficient volume of TSP to adjust the pH for all water injected. The minimum required volume of TSP is the volume that will achieve a post-LOCA borated water mixture pH of ≥ 7.0, conservatively considering the maximum possible sump water volume and the maximum possible boron concentration. The amount of TSP required is based on the mass of TSP needed to achieve the required pH. However, a required volume is verified by the SR, rather than the mass, since it is not feasible to weigh the entire amount of TSP in containment. The minimum required volume is based on the manufactured density of TSP (53 lb/ft^3). Since TSP can have a tendency to agglomerate from high humidity in the containment, the density may increase and the volume decrease during normal plant operation, however, solubility characteristics are not expected to change. Therefore, considering possible agglomeration and increase in density, verifying the minimum volume of TSP in the storage baskets is conservative with respect to ensuring the capability to achieve the minimum required pH. This SR is performed to verify the availability of sufficient TSP in the TSP storage baskets. A volume of ≥ 290 ft^3 of TSP will produce a pH range between 7.0 and 8.0 within 4 hours and therefore, will create the desired pH level of the containment spray. The 24 month Frequency is based on the low probability of undetected change in the TSP volume occurring during the SR interval (the TSP is contained in storage baskets located in the containment normal sump and on the 565 ft elevation of containment).

REFERENCES

1. UFSAR, Section 9.3.3.2.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND	The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) 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, as described in the UFSAR, Section 10.3 (Ref. 1). The MSSV rated capacity is 14.175E6 lb/hr, which is approximately 115% of the total secondary system design flow. This meets the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes two setpoints, according to Table 3.7.1-1.
APPLICABLE SAFETY ANALYSES	The design basis of the MSSVs comes from Reference 2 and its purpose is to limit secondary system pressure to ≤ 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 relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, and are presented in the UFSAR, Section 15 (Ref. 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 are not available to relieve Main Steam System pressure. Similarly, MSSV relief capacity is utilized in the UFSAR for mitigation of the following events: a. Loss of main feedwater; b. Main steam line break; c. Steam generator tube rupture; d. Excessive heat removal due to feedwater system malfunction; and e. Small break loss of coolant accident. The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The MSSVs setpoints are established to prevent overpressurization as discussed in the Applicable Safety Analysis section of these Bases. The LCO requires all MSSVs to be OPERABLE to ensure compliance with the ASME Code following DBAs initiated at full power. Operation with less than a full complement of MSSVs requires limitations on unit THERMAL POWER and adjustment of the Reactor Protection System (RPS) trip setpoints. This effectively limits the Main Steam System steam flow while the MSSV relieving capacity is reduced due to valve inoperability. To be OPERABLE, lift setpoints must remain within limits, according to Table 3.7.1-1.

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 Testing Program.

The lift settings, according to 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 the design safety function to mitigate the consequences of accidents that could result in a challenge to the RCPB.

APPLICABILITY

To support 100% RTP operation, all nine MSSVs on a steam generator are required to be OPERABLE. However, MODE 1 operation is permitted with inoperable MSSVs, provided the maximum permissible power level is reduced to a value less than that determined by Equation 3.7.1-1. In addition, in MODES 1, 2, and 3 at least two MSSVs per steam generator must be OPERABLE, one of which must have a lift setting of 1050 psig ± 3%.

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.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1 and A.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,

BASES

ACTIONS

A.1 and A.2 (continued)

provided the THERMAL POWER and RPS High Flux trip setpoint are reduced by the application of the following formulas:

$$RP = Y / Z \times 100\%$$

and

$$SP = Y / Z \times W$$

where:

W = High Flux trip setpoint for four pump operation as specified in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation;"

Y = Total OPERABLE MSSV relieving capacity per steam generator based on a summation of individual OPERABLE MSSV relief capacities per steam generator lb/hour;

Z = Required relieving capacity per steam generator of 6,585,600 lb/hour;

RP = Reduced power requirement (not to exceed RTP); and

SP = High Flux trip setpoint (not to exceed W).

The individual relief capacity of the two MSSVs with a normal setpoint of 1050 psig is 583,574 lb/hr and the individual relief capacity of the other MSSVs is 845,759 lb/hr.

These equations are provided in Equation 3.7.1-1.

The operator should limit the maximum steady state power level to some value slightly below this setpoint to avoid an inadvertent High Flux trip.

The 4 hour Completion Time for Required Action A.1 is a reasonable time period to reduce power level and is based on the low probability of an event occurring during this period that would require activation of the MSSVs. An additional 32 hours is allowed in Required Action A.2 to reduce the High Flux trip setpoints. The Completion Time of 36 hours for Required Action A.2 is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, 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.

BASES

ACTIONS (continued)

B.1 and B.2

If any Required Action and associated Completion Time of Condition A is not met, if one or more steam generators have less than two OPERABLE MSSVs, or if one or more steam generators have no OPERABLE MSSVs with a lift setpoint of 1050 psig ± 3%, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The MSSV tests are to be performed in accordance with ASME OM Code (Ref. 4). According to Reference 4, the following tests are required for MSSVs:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

The ASME OM Code requires the testing of all valves every 5 years, with a minimum of 20% of the valves from each valve group tested every 24 months. Table 3.7.1-1 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. 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.

BASES

REFERENCES

1. UFSAR, Section 10.3.
2. ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition.
3. UFSAR, Section 15.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

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 main steam or feedwater 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 main steam safety valves (MSSVs) and auxiliary 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, Turbine Bypass System, and other auxiliary steam supplies from the steam generators. The MSIVs close on a Steam and Feedwater Rupture Control System signal generated by either Main Steam Line Pressure - Low or Feedwater/Steam Generator Differential Pressure - High. 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 the UFSAR, Section 10.3 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the MSIVs is to isolate flow from the secondary side of the steam generators to limit blowdown following a main steam line break (MSLB) or a feedwater line break (FWLB), as discussed in the UFSAR, Sections 15.4.4 (Ref. 2) and 15.2.8 (Ref. 3), respectively. The MSIVs also isolate the steam generators to establish control of fission products released to the secondary system from the primary system following a steam generator tube rupture, as discussed in UFSAR, Section 15.4.2 (Ref. 4). The turbine stop valves (TSVs) also provide a means for main steam isolation in the event of an MSLB. Closure of the TSVs ensures that both steam generators do not blow down following an MSLB in conjunction with the MSIV associated with the unaffected steam generator failing to close. The TSV requirements are provided in ITS 3.7.4, "Turbine Stop Valves (TSVs)." The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that the MSIV in both steam lines be OPERABLE. The MSIVs are considered OPERABLE when the 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 (Ref. 4).

BASES

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1 and in MODES 2 and 3 with any MSIV open, when there is significant mass and energy in the RCS and steam generator; therefore, the MSIVs must be OPERABLE or closed. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, the steam generator energy is low. Therefore, the MSIVs are not required to be OPERABLE.

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.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore the MSIV to OPERABLE status within 8 hours. Some repairs can be made to the MSIV with the unit 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 turbine stop valves are also available to provide the required isolation for some accidents.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a penetration that is neither part of the reactor coolant pressure boundary nor is connected directly to the containment atmosphere.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in MODE 2 within the next 6 hours. The Completion Time is reasonable, based on operating experience, to reach MODE 2.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

BASES

ACTIONS

C.1 and C.2 (continued)

The 8 hour Completion Time is consistent with that allowed in Condition A.

Inoperable MSIVs that are closed must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure these valves are in the closed position.

D.1 and D.2

If the MSIV cannot be restored to OPERABLE status or closed in the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV is within the limit given in Reference 5 and is within that assumed in the accident analyses. This SR also verifies the valve closure time is in accordance with the Inservice Testing Program. This SR is normally performed upon returning the unit to operation following a refueling outage, because the MSIVs should not be tested at power since even a partial stroke exercise increases the risk of a valve closure with the unit generating power. As the MSIVs are not to be tested at power, they are exempt from the ASME Code (Ref. 6) requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program.

SR 3.7.2.2

This SR verifies that each MSIV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. The Frequency of MSIV testing is every 24 months. The 24 month Frequency for testing is

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.2 (continued)

based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 6.2.
3. UFSAR, Section 15.4.
4. 10 CFR 100.11.
5. Technical Requirements Manual.
6. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Stop Valves (MFSVs), Main Feedwater Control Valves (MFCVs), and associated Startup Feedwater Control Valves (SFCVs)

BASES

BACKGROUND	The main feedwater isolation valves (MFIVs) for each steam generator consist of the MFSVs, MFCVs, and the SFCVs. The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). Closure of the MFIVs 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 main steam line breaks (MSLBs) or FWLBs inside containment and reducing the cooldown effects for MSLBs. The MFIVs close on receipt of a Steam and Feedwater Rupture Control System (SFRCS) signal generated by either Main Steam Line Pressure - Low or Feedwater/Steam Generator Differential Pressure - High. The MFIVs can also be closed manually.
APPLICABLE SAFETY ANALYSES	The design basis of the MFIVs is established by the analysis for the MSLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs 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 signal. Failure of an MFIV to close following an MSLB, 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 an MSLB or FWLB event. The MFIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO ensures that the MFIVs will isolate MFW flow to the steam generators following a FWLB or a main steam line break. The MFSVs will also isolate the nonsafety related portions from the safety related portions of the system. Two MFSVs, MFCVs, and associated SFCVs are required to be OPERABLE. The MFIVs are considered OPERABLE when the isolation times are within limits and they close on an isolation actuation signal.

BASES

LCO (continued)

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an MSLB or FWLB inside containment.

APPLICABILITY

The MFSVs, MFCVs, and associated SFCVs must be OPERABLE whenever there is significant mass and energy in the RCS and steam generators. This ensures that in the event of an MSLB or FWLB, a single failure cannot result in the blowdown of more than one steam generator.

In MODES 1, 2, and 3, the MFSVs, MFCVs, and associated SFCVs 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 or isolated by a closed manual valve, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFSVs, MFCVs, and associated SFCVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one or more MFSVs inoperable, action must be taken to close or isolate the inoperable affected valve within 72 hours. When this valve is closed or isolated, it is performing its required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

An inoperable MFSV that is closed or isolated, must be verified on a periodic basis that it is closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that this valve is closed or isolated.

BASES

ACTIONS (continued)

B.1 and B.2

With one or more MFCVs inoperable, action must be taken to close or isolate the inoperable affected valve within 72 hours. When this valve is closed or isolated, it is performing its required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE MFSVs and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

An inoperable MFCV that is closed or isolated must be verified on a periodic basis that it is closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

C.1 and C.2

With one or more SFCVs inoperable, action must be taken to close or isolate the inoperable affected valve within 72 hours. When this valve is closed or isolated, it is performing its required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE MFSVs and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

An inoperable SFCV that is closed or isolated must be verified on a periodic basis that it is closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

D.1

With two inoperable valves in the same flow path (i.e., an inoperable MFSV and either an inoperable MFCV or SFCV) there is no redundant system to operate automatically and perform the required safety function. Under these conditions, the affected flow path must be isolated within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to close the MFIV or otherwise isolate the affected flow path.

BASES

ACTIONS (continued)

E.1 and E.2

If any Required Action and associated Completion Time is not met, the unit must be in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 and SR 3.7.3.2

These SRs verify that the closure time of each MFSV, MFCV, and associated SFCV is within the limit given in Reference 1 and is within the isolation time assumed in the accident analyses. SR 3.7.3.1 also verifies the valve closure time is in accordance with the Inservice Testing Program. These SRs are normally performed upon returning the unit to operation following a refueling outage. The MFSVs, MFCVs, and associated SFCV should not be tested at power since even a partial stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code (Ref. 2) requirements during operation in MODES 1 and 2.

The Frequency for SR 3.7.3.1 is in accordance with the Inservice Testing Program and for SR 3.7.3.2 is 24 months.

SR 3.7.3.3

This SR verifies that each MFSV, MFCV, and associated SFCV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency for this SR is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. Technical Requirements Manual.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.4 Turbine Stop Valves (TSVs)

BASES

BACKGROUND	The TSVs are designed to quickly shut off steam flow to the turbine and prevent turbine overspeed under emergency conditions. TSV closure also terminates flow from the unaffected (intact) steam generator following a main steam line break (MSLB). Four turbine stop valves are located in front and below the turbine unit. Steam from one steam generator passes through two of the TSVs (in parallel pathways) and steam from the other steam generator passes through the other two TSVs (in parallel pathways). The TSVs are closed on a Steam and Feedwater Rupture Control System (SFRCS) signal generated by either Main Steam Line Pressure - Low or Feedwater/Steam Generator Differential Pressure - High to prevent blowdown of both steam generators during a MSLB. A description of the turbine stop valves are found in the UFSAR, Section 10.2 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the TSVs are established by the accident analysis of the MSLB events presented in the UFSAR, Section 15.4 (Ref. 2). Credit is taken in the MSLB analysis for TSV closure. The TSVs provide a redundant means for main steam line isolation in the event of an MSLB downstream of the MSIVs. The TSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires all four TSVs to be OPERABLE. The TSVs are considered OPERABLE when the isolation times are within limits and they close on an isolation actuation signal. This LCO provides assurance that the TSVs 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 (Ref. 3).
APPLICABILITY	The TSVs must be OPERABLE in MODE 1 and in MODES 2 and 3 with any TSV open, when there is significant mass and energy in the Reactor Coolant System and steam generator; therefore, the TSVs must be OPERABLE or closed. When all the TSVs are closed, they are already performing the safety function. In MODE 4, the steam generator energy is low. Therefore, the TSVs are not required to be OPERABLE.

BASES

APPLICABILITY (continued)

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 TSVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

The ACTIONS Table is modified by a NOTE indicating that separate Condition entry is allowed for each TSV.

A.1 and A.2

With one TSV inoperable, action must be taken to close the inoperable TSV within 8 hours. The 8 hour Completion Time is reasonable, considering the probability of an accident that would require actuation of the TSVs occurring during this time interval. The MSIVs are also available to provide the required isolation for the postulated accidents.

Inoperable TSVs that are closed must be verified on a periodic basis that they are closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of TSV status indications available in the control room, and other administrative controls, to ensure that these valves are closed.

B.1 and B.2

If any Required Action and associated Completion Time cannot be met, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 1 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the closure time of each TSV is within the limits in Reference 4 and is within that assumed in the accident and containment analyses. This SR is normally performed upon returning the unit to operation following a refueling outage, because the TSVs should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1 (continued)

The Frequency of TSV testing is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

This SR verifies that each TSV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

The Frequency of TSV testing is every 24 months. The 24 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 10.2.
2. UFSAR, Section 15.4.
3. 10 CFR 100.
4. Technical Requirements Manual.

B 3.7 PLANT SYSTEMS

B 3.7.5 Emergency Feedwater (EFW)

BASES

BACKGROUND

Emergency Feedwater (EFW) consists of two Auxiliary Feedwater (AFW) trains and the Motor Driven Feedwater Pump (MDFP) train.

The AFW System provides a safety related source of feedwater to the secondary side of the steam generators in the event of a loss of normal feedwater flow to remove reactor decay heat. The AFW pumps take suction from the condensate storage tanks (CSTs) (LCO 3.7.6, "Condensate Storage Tanks (CSTs)"), and pump to the steam generator secondary side through the AFW 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, "Main Steam Safety Valves (MSSVs)"), or atmospheric vent valves.

The AFW System consists of two steam turbine driven AFW pumps, each of which provides a nominal 100% capacity. The steam turbine driven AFW pumps receive steam from either of the two main steam headers, upstream of the main steam isolation valves (MSIVs). The AFW System supplies water via two headers, each capable of feeding either steam generator. The 100% capacity is sufficient to remove decay heat and cool the unit to Decay Heat Removal (DHR) System entry conditions. The AFW System normally receives a supply of water from the CSTs. 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 CSTs to the SWS. A third source of water can be supplied by manually aligning the fire protection header to the AFW pump suction.

The MDFP train provides feedwater to the steam generators during normal plant startup and shutdown. The MDFP train is also designed to provide a backup supply of feedwater to the steam generators in the event of a total loss of both AFW and main feedwater (MFW). The MDFP train can be aligned to take suction from the condensate storage tanks, deaerator storage tanks, or the SWS. The MDFP discharge can be aligned to either the AFW System or the MFW System. During plant operation when reactor power is > 40% RTP, the MDFP train is aligned as an EFW train and is capable of delivering water to both steam generators. In addition, since the MDFP uses the AFW flowpaths to discharge to the steam generators, the position of the steam generator inlet valves affects the MDFP in addition to the AFW pumps.

BASES

BACKGROUND (continued)

The MDFP train is non-safety related and provides a diverse means of supplying emergency feedwater to the steam generators.

EFW is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

EFW is designed to supply sufficient water to cool the unit to DHR System entry conditions with steam being released through the MSSVs or atmospheric vent valves.

The AFW System actuates automatically on a Steam and Feedwater Rupture Control System (SFRCS) actuation signal (i.e., Main Steam Line Pressure - Low, Feedwater/Steam Generator Differential Pressure - High, Steam Generator Level - Low, and Loss of RCPs).

EFW is discussed in the UFSAR, Sections 9.2.7 and 9.2.8 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with a loss of normal feedwater.

The design basis of the AFW 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 main steam safety valve set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory being lost as steam as the unit cools to MODE 4 conditions.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Main steam line break (MSLB); and

b. Loss of main feedwater.

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident.

The AFW System design is such that it can perform its function following a loss of the turbine driven main feedwater pumps following a loss of offsite power.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MDFP train is not credited in any accident analysis; however in the event of a line break in the steam supply piping of one AFW pump turbine and a single failure in the redundant AFW train, the MDFP train is capable of providing emergency feedwater to the steam generators.

The AFW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) and the MDFP train satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides assurance that EFW will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three EFW trains (consisting of two AFW trains and the MDFP train) are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two AFW pumps by steam driven turbines supplied with steam from a source not isolated by the closure of the MSIVs, and one motor driven pump from a power source that, in the event of loss of offsite power, can be supplied by an emergency diesel generator.

EFW is considered to be OPERABLE when the components and flow paths required to provide EFW flow to the steam generators are OPERABLE. This requires that each of the two AFW pumps be OPERABLE with redundant steam supplies from each of the main steam lines upstream of the MSIVs and each capable of supplying EFW flow to both of the steam generators (except when a steam generator is inoperable and isolated). The nonsafety grade MDFP and associated flow paths to the AFW System are also required to be OPERABLE and capable of supplying flow to both steam generators (except when a steam generator is inoperable and isolated). The piping, valves, instrumentation, and controls in the required flow paths shall also be OPERABLE. The primary and secondary sources of water to AFW are required to be OPERABLE. The associated flow paths from AFW primary and secondary sources of water to the AFW pumps also are required to be OPERABLE. The primary source of water to the MDFP, as well as the associated flowpath from the primary source of water to the MDFP, is required to be OPERABLE.

This LCO is modified by a Note indicating that the MDFP train is required 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 AFW pumps.

BASES

APPLICABILITY

In MODES 1, 2, and 3, EFW is required to be OPERABLE and to function in the event that the main feedwater is lost. In addition, EFW is required to supply enough makeup water to replace the steam generator secondary inventory lost as the unit cools to MODE 4 conditions.

In MODE 4, EFW may be used for heat removal via the steam generators. In MODE 4, the steam generators are used for heat removal until the DHR System is in operation.

In MODES 5 and 6, the steam generators are not used for heat removal and EFW is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable EFW train when entering MODE 1. There is an increased risk associated with entering MODE 1 with EFW inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With one AFW train inoperable due to one inoperable steam supply, or if an AFW train is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of an AFW train due to one inoperable steam supply, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the AFW train and the AFW train is still capable of performing its specified function for most postulated events.

b. For the inoperability of an AFW train while in MODE 3 immediately subsequent to a refueling, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation.

c. In addition, for either the inoperability of an AFW train due to one inoperable steam supply or an inoperable AFW train while in MODE 3 immediately following refueling, the 7 day Completion Time is reasonable due to the availability of redundant OPERABLE EFW pumps, and due to the low probability of an event requiring the use of the inoperable AFW pump.

Condition A is modified by a Note which limits the applicability of the Condition for an inoperable AFW pump in MODE 3 to when the unit has

BASES

ACTIONS

A.1 (continued)

not entered MODE 2 following a refueling. Condition A allows one AFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

B.1

When one of the EFW trains (pump or flow path) is inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore the train to OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to one AFW train. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by EFW, time needed for repairs, and the low probability of a DBA occurring during this time period.

C.1 and C.2

With the MDFP train (pump or flow path) inoperable and one of the AFW trains inoperable due to one inoperable steam supply, action must be taken to restore the affected equipment to OPERABLE status within 48 hours. Assuming no single active failures when in this condition, the accident (a MSLB) could result in the loss of the remaining steam supply to the inoperable AFW pump due to the faulted steam generator. In this condition, the EFW may no longer be able to meet the required flow to the steam generators assumed in the safety analysis.

The 48 hour Completion Time is reasonable based on the fact that the remaining AFW train is capable of providing 100% of the EFW flow requirements, and the low probability of an event occurring that would challenge the EFW.

D.1 and D.2

When Required Action A.1, B.1, C.1, or C.2 cannot be completed within the required Completion Time, or when two EFW trains are inoperable for reasons other than Condition C in MODE 1, 2, or 3, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

BASES

ACTIONS

D.1 and D.2 (continued)

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

In MODE 4, with two AFW trains inoperable, operation is allowed to continue because only the MDFP train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate DHR.

E.1

Required Action E.1 is modified by a Note indicating that all required MODE changes are suspended until at least one EFW train is restored to OPERABLE status.

With all EFW trains inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety grade equipment. In such a condition, the unit 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. LCO 3.0.3 is not applicable, as it could force the units into a less safe condition.

F.1

In MODE 4, either the steam generator loops or the DHR loops can be used to provide heat removal, which is addressed in LCO 3.4.6, "RCS Loops - MODE 4." With the required MDFP train inoperable, action must be immediately initiated to restore the inoperable train to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the EFW water and steam supply 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 are 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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 (continued)

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.

A Note has been added that allows the MDFP train valves to be in the non-correct position (aligned in the Main Feedwater mode) when in MODE 1 ≤ 40% RTP or in MODE 2, 3, or 4, provided the valves are capable of being locally realigned to the correct position (i.e., aligned in the AFW mode). The capability of the valves to be locally realigned to the correct position is met if a handwheel is present for each manual valve and either a handwheel is present or a power supply is available for each power operated valve. This Note is necessary because the MDFP train is normally aligned to the Main Feedwater System during a reactor startup. The allowance is acceptable since the MDFP train is a manually actuated train.

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

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of pump performance required by the ASME Code (Ref. 3). Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this test is performed on recirculation flow.

This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing in the ASME Code (Ref. 3), at 3 month intervals, satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.3

This SR verifies the ability of the MDFP train to operate in the emergency feedwater mode. This SR verifies the proper operation of each power operated and automatic valve in the MDFP train flow path to the AFW System, and that the MDFP can be started and operated from the control room.

As noted, the SR is not required to be performed until 73 hours after the MDFP train is aligned to the AFW System. This Note is necessary because the MDFP train is normally aligned to the Main Feedwater System during a reactor startup. This allowance is acceptable since any inoperabilities with the MDFP train would likely be discovered during the reactor startup when it is being used in the main feedwater mode.

The 92 day Frequency is acceptable based on engineering judgment and corresponds to the testing requirements for pumps as contained in the ASME Code (Ref. 3).

SR 3.7.5.4

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an SFRCS signal by demonstrating that each AFW automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is also acceptable based on operating experience and design reliability of the equipment. This SR is modified by a Note indicating that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.5.5

This SR verifies that the AFW pumps start in the event of any accident or transient that generates an SFRCS signal by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.5 (continued)

with the reactor at power. This SR is modified by a Note indicating that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.5.6 and SR 3.7.5.7

This SR ensures that EFW is properly aligned by verifying the flow paths to each steam generator prior to entering MODE 2 (for SR 3.7.5.6) and MODE 3 (for SR 3.7.5.7), following refueling or after more than 30 days in any combination of MODE 5 or 6, or defueled. OPERABILITY of EFW flow paths must be demonstrated before sufficient core heat is generated that would require the operation of EFW during a subsequent shutdown. The flow paths shall be verified by either steam generator level change or AFW safety grade flow indication (e.g., the Post Accident Monitoring AFW Flow Rate indicators). Verification of actual AFW flow capacity is not required by this SR. The Frequency is reasonable, based on engineering judgment, in view of other administrative controls to ensure that the flow paths are OPERABLE. To further ensure EFW alignment, flow path OPERABILITY is verified, following extended outages to determine no misalignment of valves has occurred. This SR ensures that the common flow path from the CSTs to the steam generator is properly aligned.

SR 3.7.5.8, SR 3.7.5.9, and SR 3.7.5.10

These SRs are performed on each AFW train's Steam Generator Level Control System channels. This helps ensure the each AFW train properly controls steam generator level after an automatic start of the AFW train.

Performance of the CHANNEL CHECK every 12 hours ensures a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.8, SR 3.7.5.9, and SR 3.7.5.10 (continued)

criteria, it may be an indication that the detector or the signal processing equipment has drifted outside its limit. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction.

A CHANNEL FUNCTIONAL TEST is performed on each channel to ensure the entire channel will perform the intended function.

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the unit specific setpoint and tolerance.

The CHANNEL CHECK Frequency of every 12 hours is based on operating experience that demonstrates channel failure is rare. Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel operability during normal operational use of the displays associated with the LCO's required channels.

The CHANNEL FUNCTIONAL TEST Frequency of 31 days is reasonable, based on operating experience and on other Surveillances (such as a CHANNEL CHECK), that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

The CHANNEL CALIBRATION Frequency of 24 months is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

REFERENCES

1. UFSAR, Section 9.2.7.

2. UFSAR, Section 9.2.8.

3. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tanks (CSTs)

BASES

BACKGROUND	The two CSTs provide the primary source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CSTs provide a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System and the Motor Driven Feedwater Pump when aligned to the AFW mode (LCO 3.7.5, "Emergency Feedwater (EFW)"). The steam produced is released to the atmosphere by the main steam safety valves (MSSVs) or the atmospheric vent valves. The CSTs are the preferred choice for makeup water to the steam generators because they meet secondary water chemistry requirements. The CSTs are Seismic Class II. The Service Water System (SWS) is the Safety Grade source of water in the event of an earthquake. In the event of a reduction in the inventory of the CSTs (i.e., a low level in the CSTs as sensed by Auxiliary Feedwater pump low suction pressure), the Auxiliary Feedwater System supply will automatically switch from the CSTs to the Service Water System. A description of the CSTs is found in the UFSAR, Section 9.2.6 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The CSTs provide the preferred source of water for the AFW System to cool down the RCS in the event of a loss of offsite power. For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the CSTs design provides sufficient water inventory for 13 hours at MODE 3, steaming to atmosphere, followed by a cooldown to decay heat removal (DHR) entry conditions at the design cooldown rate. The CSTs satisfy Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	To satisfy design considerations, the CSTs must contain sufficient cooling water to remove decay heat for 13 hours following a reactor trip with steam discharge to the atmosphere and then to cool down the RCS to DHR System entry conditions. While so doing, the CSTs must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during the cooldown, to account for any losses from the steam driven AFW pump turbines. The CSTs must contain a usable volume of 270,300 gallons, which is based on holding the unit in MODE 3 for 13 hours, followed by a cooldown to DHR System entry conditions.

BASES

LCO (continued)

The OPERABILITY of the CSTs is determined by maintaining the usable tank volume at or above the minimum required volume.

APPLICABILITY

In MODES 1, 2, 3, and in MODE 4 when a steam generator is being relied upon for heat removal, the CSTs are required to be OPERABLE.

In MODES 5 and 6, the CSTs are not required because the AFW System is not required.

ACTIONS

A.1 and A.2

As an alternative to unit shutdown, the OPERABILITY of the backup water supply (the Service Water System) should be verified within 4 hours and once every 12 hours thereafter. The OPERABILITY of the backup feedwater supply must include verification, by administrative means, of the OPERABILITY of flow paths from the backup supply to the AFW pumps. The CSTs must be restored to OPERABLE status within 7 days because the backup supply is not the preferred source of water (i.e., it is not preferred to add this backup source of water to the steam generators). The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period, requiring the use of the water from the CSTs.

B.1 and B.2

If any Required Action and associated Completion Time is not met, the unit must be placed in a MODE in which the LCO does not apply, with the DHR System in operation. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on steam generators for heat removal, within 24 hours.

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

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.6.1 This SR verifies that the CSTs contain the required usable volume of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CSTs inventory between checks. The 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in CST levels.
REFERENCES	1. UFSAR, Section 9.2.6.

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 Design Basis Accident (DBA) or transient. 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, and thus to the environment. The CCW System is arranged as two independent full capacity cooling loops, and has isolatable nonsafety related components. The CCW System consists of three pumps, three heat exchangers, a surge tank and two closed cooling loops. Each closed cooling loop is capable of serving one train of Emergency Core Cooling System (ECCS) components and the associated emergency diesel generator (EDG). Each closed cooling loop is supplied by one of the three pumps. Three pumps and heat exchangers are provided so any one of the pump-heat exchanger units can be removed from service for maintenance or repair without reducing the capability or redundancy of the CCW System. Two of the CCW pumps are powered from the associated essential bus. The third CCW pump can be powered from either essential bus through interlocked supply breakers and can manually be aligned to supply either CCW loop. A common surge tank in the system provides sufficient net positive suction head for each pump and isolation of nonessential components on a low tank level signal. The surge tank is divided internally into two separate compartments by a center baffle approximately half the height of the tank. Each compartment serves a separate loop. This ensures that if a leak on one loop occurs, water remains available to the other loop. The pump in each loop is automatically started on receipt of a safety features actuation signal, and all nonessential components are isolated. Additional information on the design and operation of the CCW System, along with a list of the components served, is presented in the UFSAR, Section 9.2.2 (Ref. 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) cooler. 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.
APPLICABLE SAFETY ANALYSES	The design basis of the CCW System is to provide cooling water to the Emergency Core Cooling System components and EDGs during DBA conditions. The CCW System also supplies cooling water to EDGs during a loss of offsite power.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 unit from DHR entry conditions MODE 4 (T_{cold} < 280°F) to MODE 5 (T_{cold} < 200°F) during normal and post accident operations. The time required to cool from 280°F to 200°F is a function of the number of CCW and DHR loops operating. One CCW loop is sufficient to remove decay heat during subsequent operations with T_{cold} < 200°F.

The CCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The CCW loops are independent of each other to the degree that each has separate controls and power supplies and the operation of one loop does not depend on the other. In the event of a DBA, one loop 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 CCW loops must be OPERABLE. At least one CCW loop will operate assuming the worst case single active failure occurs coincident with loss of offsite power.

A CCW loop is considered OPERABLE when:

a. It has an OPERABLE pump and associated portion of the surge tank; and

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

Furthermore, the spare CCW pump and associated heat exchanger can be substituted for a normal CCW pump and heat exchanger, provided the power supply for the pump is aligned to the same essential bus as the pump it is replacing.

The isolation of CCW from other components or systems not required for safety may render the individual components or systems inoperable, but does not affect the OPERABILITY of the CCW System.

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 heat removal, by cooling the DHR cooler.

In MODES 5 and 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

BASES

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," and LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable CCW loop results in an inoperable EDG or DHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCW loop is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this condition, the remaining OPERABLE CCW loop is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE loop, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW loop 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. To achieve this status, the unit must be placed 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable, but does not affect the OPERABILITY of the CCW System.

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 are 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 is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation (i.e., SFAS) signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation (i.e, SFAS) signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.2.2.

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 Design Basis Accident (DBA) or transient. During normal operation and normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related portion is covered by this LCO.

The SWS consists of three pumps and two independent essential load cooling loops. Each essential load cooling loop is supplied by one of three pumps. One pump normally supplies the essential loads for its associated loop, and the second pump supplies the essential loads for its associated loop and all the non-essential loads. Three pumps are provided so that any one of the pumps can be removed from service for maintenance or repair without reducing the capability or redundancy of the SWS. Two of the SWS pumps are powered from the associated essential bus. The third SWS pump can be powered from either essential bus through interlocked supply breakers and can manually be aligned to supply either SWS loop. The pumps and valves are remote manually aligned, except in the unlikely event of a loss of coolant accident (LOCA). The pumps are automatically started upon receipt of a safety features actuation signal, and all essential valves are aligned to their post accident positions and valves to the non-essential loads are isolated. The SWS provides cooling to the Control Room Emergency Ventilation System water cooled condensing unit, the Emergency Core Cooling System (ECCS) pump room coolers, containment air coolers, and Component Cooling Water System heat exchangers. The SWS provides a backup source of water to the Auxiliary Feedwater System and the Motor Driven Feedwater Pump.

Additional information about the design and operation of the SWS, along with a list of the components served, is presented in the UFSAR, Section 9.2.1 (Ref. 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 loop, in conjunction with the CCW System and a 100% capacity containment cooling system, (containment spray, containment air coolers, or a combination) to remove core decay heat following a design basis LOCA, as discussed in the UFSAR, Section 6.2 (Ref. 2). This provides for a gradual reduction in the temperature of this fluid, as it is supplied to the Reactor Coolant System (RCS) by the ECCS pumps.

The SWS is designed to perform its function with a single failure of any active component, assuming loss of offsite power.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SWS, in conjunction with the CCW System, also cools the unit from Decay Heat Removal (DHR) System entry conditions to MODE 5 during normal and post accident operation, as discussed in the UFSAR, Section 6.3 (Ref. 3). The time required for this evolution is a function of the number of CCW and DHR System loops that are operating. One SWS train is sufficient to remove decay heat during subsequent operations with T_{cold} < 200°F. This assumes an initial SWS temperature of 90°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 Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two SWS loops are required to be OPERABLE to 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.

An SWS loop is considered OPERABLE when:

a. It has an OPERABLE pump; and

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

Furthermore, the spare SWS pump can be substituted for a normal SWS pump, provided the power supply for the pump is aligned to the same essential bus as the pump it is replacing.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

ACTIONS

A.1

If one SWS loop is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this condition, the remaining OPERABLE SWS loop is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SWS loop could result in loss of SWS function. Required Action A.1 is modified by two Notes. The first Note indicates that the

BASES

ACTIONS

A.1 (continued)

applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," should be entered if an inoperable SWS loop results in an inoperable EDG. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable SWS loop results in an inoperable DHR loop. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE loop, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SWS loop cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours.

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

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 are verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves.

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

This SR is modified by a Note indicating that the isolation of the SWS components or systems may render those components inoperable but does not affect the OPERABILITY of the SWS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

The SR verifies proper automatic operation of the SWS valves on an actual or simulated actuation (i.e., SFAS) signal. The SWS is a normally operating system that cannot be fully actuated as part of the normal testing. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.3

The SR verifies proper automatic operation of the SWS pumps on an actual or simulated (i.e., SFAS) actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at a 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.2.1.
2. UFSAR, Section 6.2.
3. UFSAR, Section 6.3.

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 as well as during normal operation. 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, as discussed in the UFSAR, Section 9.2.5 (Ref. 1). The two principal functions of the UHS are the dissipation of residual heat after a reactor shutdown, and dissipation of residual heat after an accident.

The ultimate heat sink is Lake Erie, and is the source of cooling water for the Service Water System. This is the single source for the ultimate heat sink, and the most severe natural phenomenon that can occur does not prevent a safe shutdown of the reactor. The Seismic Class I portion of the intake forebay provides adequate storage that is capable of providing sufficient cooling for at least 30 days. Procedures for ensuring a continued capability after this time are available. The ultimate heat sink provides adequate cooling for at least 30 days. An earthquake, which may result in loss of the source of lake water to the intake forebay, is the most severe event. This occurrence does not cause loss of the ultimate heat sink safety functions. The occurrence of extremely low lake level, which reduces the quantity of available water in the forebay, in conjunction with loss of the canal, was considered. The lowest level was assumed for the analysis, and this condition does not preclude the ultimate heat sink from performing its safety functions. The collapse of the intake pipe or complete closure of the canal was postulated for the analysis. It is demonstrated that additional sources of water are not required since the stored water in the forebay is adequate for safe shutdown. With regards to the amount of conservatism available for dissipating heat loads, the design of the ultimate heat sink is also consistent with the recommendations of Regulatory Guide 1.27, Revision 1 (Ref. 2).

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1.

BASES

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 unit is cooled down and placed on decay heat removal. Its maximum post accident heat load occurs at swapover to the containment emergency sump after a design basis loss of coolant accident (LOCA). This is when the unit 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 manmade structure). The UHS is designed consistent with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the UHS. The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The UHS is required to be OPERABLE and 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 International Great Lakes Datum during normal unit operation.
APPLICABILITY	In MODES 1, 2, 3, and 4, the UHS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the UHS and is required to be OPERABLE in these MODES. In MODES 5 and 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.
ACTIONS	<u>A.1 and A.2</u> If the UHS is inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies that adequate long term (30 days) cooling can be maintained. The level specified also ensures 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. This SR verifies that the UHS water level is ≥ 562 ft International Great Lakes Datum.

SR 3.7.9.2

This SR verifies that the SWS can cool the CCW System to at least its maximum design temperature within the maximum accident or normal heat loads for 30 days following a Design Basis Accident. The 24 hour Frequency is based on operating experience related to the trending of the parameter variations during the applicable MODES. This SR verifies that the UHS average water temperature is ≤ 90°F.

REFERENCES

1. UFSAR, Section 9.2.5.

2. Regulatory Guide 1.27, Revision 1.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The CREVS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREVS consists of two independent, redundant trains that recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CREVS train consists of a roughing filter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and also encompasses other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CREVS is an emergency system. Upon receipt of the activating signal(s), the Control Room Normal Ventilation System is automatically isolated, which isolates the CRE boundary, and the CREVS can be manually started. The roughing filters remove any large particles in the air to prevent excessive loading of the HEPA and charcoal filters.

A single CREVS train operating at a flow rate of ≤ 3300 cfm (approximately 300 cfm of outside air and 3000 cfm of recirculation air) will pressurize the CRE to about 1/8 inch water gauge relative to external areas adjacent to the CRE boundary. The CREVS operation is discussed in the UFSAR, Section 9.4.1 (Ref. 1).

BASES

BACKGROUND (continued)

The CREVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA), without exceeding a 5 rem whole body dose or its equivalent to any part of the body.

APPLICABLE SAFETY ANALYSES

The CREVS components are arranged in redundant safety related ventilation trains. The location of components, and the ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CREVS provides airborne radiological protection for the CRE occupants as demonstrated by the CRE occupant dose analyses for the most limiting design basis loss of coolant accident fission product release presented in the UFSAR, Section 15.4.6 (Ref. 2).

The CREVS provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 3). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Refs. 3 and 4).

Furthermore, the fuel handling accident, both inside and outside containment, assumes the control room is isolated (Ref. 5).

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.

The CREVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant CREVS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of a large radioactive release.

Each CREVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CREVS train is considered OPERABLE when the associated:

a. Fan is OPERABLE;

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

BASES

LCO (continued)

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

In order for the CREVS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke. Maintaining the CRE boundary OPERABLE includes the capability to isolate the Control Room Normal Ventilation System.

The LCO is modified by a Note (Note 1) allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated. The LCO is modified by a second Note (Note 2) indicating that only the CRE boundary is required during movement of irradiated fuel assemblies. This is because the fuel handling accident analyses (Ref. 5) does not assume CREVS operation, only that the control room is isolated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

During movement of irradiated fuel assemblies, the CRE boundary must be OPERABLE to cope with a release due to a fuel handling accident.

ACTIONS

A.1

With one CREVS train inoperable for reasons other than an inoperable CRE boundary, action must be taken to restore the inoperable CREVS train to OPERABLE status within 7 days. In this condition, the remaining OPERABLE CREVS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

BASES

ACTIONS (continued)

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

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be immediately initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3 (Ref. 6), which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 7). These compensatory measures may be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may be used as compensatory measures to restore OPERABILITY (Ref. 8). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status. The 24 hour Completion Time of Required Action B.2 is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time of Required Action B.3 is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

BASES

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, 3, or 4, if any Required Action and associated Completion Time of Condition A or B cannot be met, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

During movement of irradiated fuel assemblies, if the CRE boundary is inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

E.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4 for reasons other than an inoperable CRE boundary (i.e., Condition B), the CREVS may not be capable of performing the intended function and the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once every month adequately checks this system. Initiating each train from the control room, with flow through the HEPA filters and charcoal adsorbers, and operating for ≥ 15 minutes demonstrates the function of each train. The 31 day Frequency is based on the known reliability of the equipment and the two train redundancy available.

SR 3.7.10.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.2 (continued)

efficiency, 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 3.7.10.3

This SR verifies that the Control Room Normal Ventilation System isolates on an actual or simulated actuation (i.e., SFAS and Station Vent Normal Range Radiation Monitoring) signal. The Frequency of 24 months is based on operating experience and is consistent with the typical refueling cycle.

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered.

SR 3.7.10.5

This SR verifies the CREVS can supply the CRE with outside air to meet the design requirement. The Frequency of 24 months is consistent with industry practice and other filtration SRs.

REFERENCES

1. UFSAR, Section 9.4.1.

2. UFSAR, Section 15.4.6.

3. UFSAR, Section 6.4.

BASES

REFERENCES (continued)

4. UFSAR, Section 9.5.

5. UFSAR, Section 15.4.7.

6. Regulatory Guide 1.196.

7. NEI 99-03, "Control Room Habitability Assessment," June 2001.

8. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability" (ADAMS Accession No. ML040300694).

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Emergency Air Temperature Control System (CREATCS)

BASES

BACKGROUND	The CREATCS provides temperature control for the control room following isolation of the control room. The CREATCS consists of two independent and redundant trains that provide cooling of recirculated control room air. 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 the water cooled and air cooled condensing units must be OPERABLE for the CREATCS to be OPERABLE. During emergency operation, the CREATCS maintains the temperature ≤ 110°F in the control room. The CREATCS is a subsystem providing air temperature control for the control room. The CREATCS is an emergency system. On a Safety Features Actuation System (SFAS) signal or a high radiation signal from one of the Station Vent Normal Range Radiation Monitors, the Control Room Normal Ventilation System is automatically shut down, and the Control Room Emergency Ventilation System (CREVS) can be manually started. Operation of the CREVS is required for CREATCS to be in operation. A single train will provide the required temperature control. The CREATCS operation to maintain control room temperature is discussed in the UFSAR, Section 9.4.1 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the CREATCS is to maintain control room temperature for 30 days of continuous occupancy. The CREATCS components are arranged in redundant, safety related trains. During emergency operation, the CREATCS maintains the temperature ≤ 110°F in the control room. A single active failure of a CREATCS component does not impair the ability of the system to perform as designed. The CREATCS is designed in accordance with Seismic Category I requirements. The CREATCS 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 CREATCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Two independent and redundant trains of the CREATCS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

A CREATCS train is considered OPERABLE when the individual components that are necessary to maintain control room temperature are OPERABLE. These components include the cooling coils, water and air cooled condensing units, and associated temperature control instrumentation. In addition, each CREATCS train must be OPERABLE to the extent that air circulation can be maintained.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREATCS must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY requirements following isolation of the control room.

ACTIONS

A.1

With one CREATCS train inoperable, action must be taken to restore the inoperable CREATCS train to OPERABLE status within 30 days. In this condition, the remaining OPERABLE CREATCS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a failure in the OPERABLE CREATCS train could result in a loss of CREATCS function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room isolation, the consideration that the remaining train can provide the required capabilities, and the alternate nonsafety related cooling means that are available.

B.1 and B.2

If the inoperable CREATCS train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the safety analyses. This SR consists of a combination of testing and calculations. A 24 month Frequency is appropriate, as significant degradation of the CREATCS is slow and is not expected over this time period.

BASES

REFERENCES 1. UFSAR, Section 9.4.1.

B 3.7 PLANT SYSTEMS

B 3.7.12 Station Emergency Ventilation System (EVS)

BASES

BACKGROUND

The function of the Station Emergency Ventilation System (EVS) is to collect and process potential leakage from the containment vessel to minimize environmental activity levels resulting from all sources of containment leakage following a loss of coolant accident (LOCA).

The Station EVS is required to:

a. Maintain a negative pressure (minimum of ¼ inch water gauge), with respect to outside atmosphere, within the annular space between the shield building and the containment vessel and in the penetration rooms following a LOCA; and

b. Provide a filtered exhaust path from the shield building annulus and the penetration and pump rooms following a LOCA.

The Station EVS consists of two independent, redundant trains. Each train consists of a prefilter, 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.

Normally, the Station EVS is idle during normal plant operations. Following a LOCA, an Incident Level 1 Safety Features Actuation System (SFAS) signal (Containment Pressure - High or Reactor Coolant System Pressure - Low) will start both fans and then the Station EVS suction dampers and the discharge dampers to the station vent stack will open. The recirculating dampers remain closed until the annulus differential pressure reaches the setpoint. Interconnecting dampers CV5024 and CV5025 will be automatically closed (if they are open) by the SFAS signal in the event of a LOCA. The Level 1 SFAS signal will also isolate the area being serviced by the Station EVS by closing the Containment Purge and Exhaust System valves and the ECCS pump room isolation valves to ensure that the Station EVS can draw down the shield building area to the required negative pressure. Prefilters are provided to remove coarse airborne particles to prolong HEPA filter life. HEPA filters are provided to remove fine airborne particulates that penetrate the prefilter. The activated charcoal adsorbers are impregnated to remove methyl iodide as well as elemental iodine contaminants resulting from a LOCA.

The Station EVS is discussed in the UFSAR, Sections 6.2.3, 9.4.2.2, and 15.4.6 (Refs. 1, 2, and 3, respectively).

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the Station EVS is established by the large break LOCA. The system evaluation assumes a passive failure of the ECCS outside containment, such as an ECCS pump seal failure during the recirculation mode. In such a case, the system limits radioactive release to within 10 CFR 100 (Ref. 4) requirements. The analysis of the effects and consequences of a large break LOCA is presented in Reference 3.

Two types of system failures affected in the accident analysis assumptions: 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 SFAS signal starts the Station EVS fans and opens the Station EVS suction dampers and the discharge dampers to the station vent stack. The SFAS signal closes all containment isolation valves, mechanical penetration room dampers, Purge and Exhaust System valves, and the connection between the Emergency Ventilation System and the spent fuel pool area. The purge system fans, if running, are shut down automatically.

The Station EVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the Station EVS are required to be OPERABLE 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 Reference 4 limits in the event of a Design Basis Accident (DBA).

The Station EVS is considered OPERABLE when the individual components necessary to maintain the negative pressure area boundary filtration are OPERABLE in both trains.

A Station EVS 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; and

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

Furthermore, the list of access openings required to be closed to ensure the shield building area negative pressure boundary is intact is provided in Reference 5.

BASES

LCO (continued)

The LCO is modified by a Note allowing the shield building area negative pressure boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for shield building area negative pressure isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the Station EVS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODES 5 and 6, the Station EVS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

With one Station EVS train inoperable, action must be taken to restore the inoperable Station EVS train to OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the Station EVS safety function. However, the overall reliability is reduced because a single failure in the OPERABLE Station EVS train could result in loss of Station EVS 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 ability of the remaining train to provide the required capability.

B.1

If the shield building area negative pressure boundary is inoperable, the Station EVS trains cannot perform their intended functions. Actions must be taken to restore the shield building area negative pressure boundary to OPERABLE status within 24 hours. During the period that the shield building area negative pressure boundary is inoperable, other required functions of the inoperable barrier are assessed, and appropriate compensatory measures are utilized. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of appropriate compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possibly repair, and test most problems with the shield building area negative pressure boundary.

BASES

ACTIONS (continued)

C.1 and C.2

If the Station EVS train or the shield building area negative pressure boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Standby systems should be checked periodically to ensure that they 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. Initiating each train from the control room, with flow through the HEPA filters and charcoal adsorbers, and operating for ≥ 15 minutes demonstrates the function of each train. The 31 day Frequency is based on known reliability of equipment and the two train redundancy available.

SR 3.7.12.2

This SR verifies that the required Station EVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, 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 3.7.12.3

This SR verifies that each Station EVS train starts and operates on an actual or simulated actuation (i.e., containment isolation) signal. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.4

This SR verifies the integrity of the shield building area negative pressure boundary. The ability of the Station EVS to attain a negative pressure in the annulus is periodically tested to verify proper functioning of the Station EVS. During the post accident mode of operation, the Station EVS is designed to maintain a slight negative pressure in the shield building area negative pressure boundary with respect to adjacent areas to prevent unfiltered leakage. The Station EVS is designed to attain this negative pressure at a flow rate of ≥ 7200 cfm and ≤ 8800 cfm from the shield building area negative pressure boundary. The Surveillance is performed with the flow path established prior to starting the Station EVS fan, and the other dampers associated with the Shield Building area negative pressure boundary closed. The 4 seconds required to attain a negative pressure of ≥ 0.25 inches water gauge is based on: an assumed leakage area of 2.4 square feet; and a starting pressure of zero at the required flowrate. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry practice.

SR 3.7.12.5

Operating each Station EVS filter cooling bypass damper (i.e., EVS fans cross tie dampers, CV5056 and CV5057) is necessary to ensure that the system functions properly. The OPERABILITY of the Station EVS filter cooling bypass damper is verified if it can be opened. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 6.2.3.
2. UFSAR, Section 9.4.2.2.
3. UFSAR, Section 15.4.6.
4. 10 CFR 100.11.
5. Technical Requirements Manual.

B 3.7 PLANT SYSTEMS

B 3.7.13 Spent Fuel Pool Area Emergency Ventilation System (EVS)

BASES

BACKGROUND

The Spent Fuel Pool Area EVS provides negative pressure in the spent fuel pool area, and filters airborne radioactive particulates from the area of the spent fuel pool following a fuel handling accident. With the containment equipment hatch open, the spent fuel pool area negative pressure boundary extends to include the inside of the containment pressure vessel.

The Spent Fuel Pool Area EVS 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 Spent Fuel Pool Area EVS 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 Station EVS used by the Spent Fuel Pool Area EVS consists of two independent, redundant trains. Each train consists of a prefilter, 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. Two dampers are installed in series in the ductwork between the FHAVS and the Station EVS to provide isolation of the Station EVS from the FHAVS on an Safety Features Actuation Signal. These dampers are normally open. The Station EVS is the subject of LCO 3.7.12, "Station Emergency Ventilation System (EVS)," and is fully described in the UFSAR, Section 6.2.3 (Ref. 1). A ductwork bypass with redundant dampers connects the FHAVS to the Station 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 train), located at the suction of the FHAVS exhaust fan ducting, send signals to isolate the FHAVS supply and exhaust fans and ductwork, open the redundant dampers in the bypass ductwork, and start the Station EVS fans. The Station EVS fans pull the air from the fuel handling area, creating a negative pressure, and discharge the filtered air to the station vent.

Specifically, when the Fuel Handling Exhaust - High Radiation instrumentation detects a radiation level in excess of the high radiation setpoint, a signal from the applicable radiation monitor is sent to the logic for the FHAVS and the Spent Fuel Pool Area EVS. The FHAVS supply and exhaust fans will trip and their respective inlet and outlet dampers will isolate. The Fuel Handling Area to Emergency Ventilation dampers open

BASES

BACKGROUND (continued)

and the Station EVS fans start. This will maintain a negative pressure in the Spent Fuel Pool Area and filter the exhaust through charcoal filters and HEPA filters. Filtration of the exhaust ensures the accident dose at the site boundary will be well below the 10 CFR 100 limits and the control room dose will be within the 10 CFR 50, GDC 19 limits.

APPLICABLE SAFETY ANALYSES

The Spent Fuel Pool Area EVS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident (outside containment). The analysis of the fuel handling accident, given in Reference 2, assumes that a certain number of fuel rods in an assembly are damaged. The DBA analysis of the fuel handling accident assumes that the Spent Fuel Pool Area EVS actuation aligns the ventilation flow path through the HEPA and charcoal filters prior to discharging to the station vent. These assumptions and the analysis follow the guidance provided in Regulatory Guide 1.25 (Ref. 3).

The Spent Fuel Pool Area EVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the Spent Fuel Pool Area EVS are required to be OPERABLE to ensure that at least one is available, assuming a single failure that disables the other train. Total system failure could result in the atmospheric release from the fuel handling area exceeding 10 CFR 100 (Ref. 4) limits in the event of a fuel handling accident.

The Spent Fuel Pool Area EVS is considered OPERABLE when the individual components necessary to ensure offsite and control room dose limits are not exceeded are OPERABLE in both trains. A Spent Fuel Pool Area EVS 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; and

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

The LCO is modified by a Note allowing the spent fuel pool area negative pressure boundary to be opened under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This

BASES

LCO (continued)

individual will have a method to rapidly close the opening when a need for spent fuel pool area negative pressure boundary isolation is indicated. In addition, when the spent fuel pool area negative pressure boundary includes the containment (i.e., when the containment equipment hatch is open - hatch not closed and held in place by four bolts) and the boundary is open due to both containment personnel air lock doors being open, then the administrative controls also include ensuring at least one of the air lock doors is capable of being closed and the above described dedicated individual must be immediately outside the personnel air lock.

APPLICABILITY

During movement of irradiated fuel assemblies in the spent fuel pool building, the Spent Fuel Pool Area EVS is always required to be OPERABLE to mitigate the consequences of a fuel handling accident.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

A.1

With one Spent Fuel Pool Area EVS train inoperable, action must be taken to restore the inoperable Spent Fuel Pool Area EVS train to OPERABLE status within 7 days. During this time period, the remaining OPERABLE train is adequate to perform the Spent Fuel Pool Area EVS function. However, the overall reliability is reduced because a single failure in the OPERABLE Spent Fuel Pool Area EVS train could result in a loss of Spent Fuel Pool Area EVS function. The 7 day Completion Time is based on the risk from an event occurring requiring the inoperable Spent Fuel Pool Area EVS train, and ability of the remaining Spent Fuel Pool Area EVS train to provide the required protection.

B.1 and B.2

If the inoperable Spent Fuel Pool Area EVS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE Spent Fuel Pool Area EVS train must be started immediately or irradiated

BASES

ACTIONS

B.1 and B.2 (continued)

fuel movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing 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 irradiated fuel movement in the spent fuel pool building, which precludes a fuel handling accident. This action does not preclude the movement of fuel assemblies to a safe position.

C.1

When two trains of the Spent Fuel Pool Area EVS are inoperable, the unit must be placed in a condition in which the LCO does not apply. This LCO involves immediately suspending movement of irradiated fuel assemblies in the spent fuel pool building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they 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. Initiating each train from the control room, with flow through the HEPA filters and charcoal adsorbers, and operating for ≥ 15 minutes demonstrates the function of each train. The 31 day Frequency is based on the known reliability of the equipment and the two train redundancy available.

SR 3.7.13.2

This SR verifies that the required Spent Fuel Pool Area EVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.3

This SR verifies that each Spent Fuel Pool Area EVS train actuates on an actual or simulated actuation (i.e., Fuel Handling Exhaust - High Radiation) signal. This test includes ensuring the FHAVS supply and exhaust fans trip and their respective inlet and outlet dampers close, the Fuel Handling Area to Emergency Ventilation dampers open, and the Station EVS fans start. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.13.4

This SR verifies the integrity of the spent fuel pool area negative pressure boundary. The ability of the spent fuel pool area negative pressure boundary (which includes the containment if the containment equipment hatch is open) to maintain a negative pressure, with respect to outside atmosphere, is periodically tested to verify proper function of the Spent Fuel Pool Area EVS. During the post accident mode of operation, the Spent Fuel Pool Area EVS is designed to maintain a slight negative pressure in the spent fuel pool area negative pressure boundary to prevent unfiltered leakage. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry practice.

SR 3.7.13.5

Operating each Spent Fuel Pool Area EVS filter cooling bypass damper (i.e., EVS fans cross tie dampers, CV5056 and CV5057) is necessary to ensure that the system functions properly. The OPERABILITY of the Spent Fuel Pool Area EVS filter cooling bypass damper is verified if it can be opened. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 6.2.3.
2. UFSAR, Section 15.4.7.
3. Regulatory Guide 1.25.
4. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel 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 filled to their maximum capacity. The water also provides shielding during the movement of spent fuel. A general description of the spent fuel pool design is given in the UFSAR, Section 9.1.2, Reference 1. The Spent Fuel Pool Cooling and Cleanup System is given in the UFSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the UFSAR, Section 15.4.7 (Ref. 3).
APPLICABLE SAFETY ANALYSES	The minimum water level in the spent fuel pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.25 (Ref. 4). The resultant 2 hour thyroid dose to a person at the exclusion area boundary is below 10 CFR 100 (Ref. 5) guidelines. According to Reference 4, 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 Reference 4 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. The fuel handling accident assumes the entire outer row of fuel rods in the assembly, 56 fuel rods out of 208 total fuel rods, suffer mechanical damage to the cladding. The spent fuel pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required for irradiated fuel movement within the spent fuel pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the spent fuel pool since the potential for a release of fission products exists.

BASES

ACTIONS

A.1

When the initial conditions for an accident cannot be met, immediate action must be taken to preclude the occurrence of an accident. With the spent fuel pool at less than the required level, the movement of irradiated fuel assemblies in the spent fuel pool is immediately suspended. This effectively precludes the occurrence of a fuel handling accident. In such a case, unit procedures control the movement of loads over the spent fuel. This does not preclude movement of a fuel assembly to a safe position.

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies that sufficient spent fuel pool water is available in the event of a fuel handling accident. The water level in the spent fuel pool must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by unit procedures and are acceptable, based on operating experience.

During refueling operations, the level in the spent fuel pool is at equilibrium with that in the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. UFSAR, Section 9.1.2.
2. UFSAR, Section 9.1.3.
3. UFSAR, Section 15.4.7.
4. Regulatory Guide 1.25.
5. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND	As described in LCO 3.7.16, "Spent Fuel Pool Storage," fuel assemblies are stored in the spent fuel pool racks in a Mixed Zone Three Region, Checkerboard, or Homogenous Loading pattern in accordance with criteria based on initial enrichment and assembly burnup. The high density spent fuel pool storage racks in the Spent Fuel Pool (SFP) are designed to assure that the effective neutron multiplication factor, k_{eff}, is ≤ 0.95 with the racks fully loaded with fuel of the highest anticipated reactivity and flooded with unborated water.
APPLICABLE SAFETY ANALYSES	Reactivity effects of abnormal and accident conditions have been evaluated to assure that under credible abnormal and accident conditions, the reactivity will not exceed 0.95, with credit for soluble boron in the pool water. Assuring the presence of soluble poison during fuel handling operations precludes the possibility of the simultaneous occurrence of two independent accident conditions. Three potential accident scenarios, misloaded fresh fuel assembly, mislocated fresh fuel assembly, and a dropped fuel assembly, were analyzed to determine the effect the accidents would have on the effective neutron multiplication factor, k_{eff}. The results of the analysis determined that a minimum boron concentration of 630 ppm in the SFP water is required to maintain k_{eff} ≤ 0.95 for the worst-case accident scenario (i.e., a 5.05 weight percent enriched fresh fuel assembly misloaded in a Checkerboard pattern) (Ref. 1). The minimum boron concentration value of 630 ppm bounds all analyzed potential accident scenarios discussed below. A misloaded fresh fuel assembly accident scenario analyzed misloading the assembly in the following five different locations: 1) misloading in the Mixed Zone Three Region (MZTR) inner rack 10x9; 2) misloading in the MZTR inner rack 10x9 (different location of a fresh assembly); 3) misloading in the MZTR side rack 10x8; 4) misloading in Homogeneous (45 BU) inner rack 10x9, and; 5) misloading in Checkerboard inner rack 10x9. The worst case scenario, misloading in Checkerboard inner rack 10x9, requires a minimum boron concentration of 627 ppm to assure that k_{eff} does not exceed 0.95. The second potential accident scenario considers the mislocation of a fresh fuel assembly outside of a storage rack adjacent to other fuel assemblies. The worst case would be an assembly mislocated in a corner on the west side of the pool (next to MZTR outer rack 10x8 – 7x1). This scenario requires a minimum boron concentration of 448 ppm to assure that k_{eff} does not exceed 0.95.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The dropped fuel assembly accident considers three different scenarios: a dropped fuel assembly coming to rest horizontally on top of the rack; a dropped fuel assembly came to rest vertically into a location occupied by another assembly, and; dropping the fuel assembly into an unoccupied cell. In all cases, a minimum boron concentration of 53 ppm is adequate to assure that k_{eff} does not exceed 0.95.

The concentration of dissolved boron in the spent fuel pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specified concentration ≥ 630 ppm of dissolved boron in the spent fuel pool preserves the assumption used in the analyses of the potential accident scenarios described above. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the spent fuel pool.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel pool, until a spent fuel pool verification has been performed following the last movement of fuel assemblies in the spent fuel pool. This LCO does not apply following the verification since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movement in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

ACTIONS

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

When the concentration of boron in the spent fuel pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of the fuel assemblies. This does not preclude movement of a fuel assembly to a safe position. The concentration of boron is restored simultaneously with suspending movement of the fuel assemblies. Alternatively, beginning a verification of the spent fuel pool locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored.

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not a sufficient reason to require a reactor shutdown.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies that the concentration of boron in the spent fuel pool is within the required limit. As long as this SR is met, the analyzed incidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over a short period of time.

REFERENCES

1. UFSAR, Section 9.1.2.1.

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Pool Storage

BASES

BACKGROUND	The spent fuel storage facility is designed to store either new (nonirradiated) nuclear fuel assemblies, or burned (irradiated) fuel assemblies in a vertical configuration underwater. The high density spent fuel pool storage racks are designed to maintain a k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, which includes a conservative allowance for manufacturing tolerances and calculation uncertainty. The spent fuel pool facility is designed to assure the safe storage of irradiated fuel assemblies under normal and accident conditions. Each storage rack consists of a rectangular array of stainless steel cells with walls of 0.075 inches nominal thickness, spaced a nominal 9.22 inches on center in both directions. The neutron absorber material is utilized between each cell for criticality considerations. The 21 spent fuel pool racks store a maximum of 1624 fuel assemblies. The rack cells are arranged in parallel rows with a center-to-center spacing of 9.22 inches.
APPLICABLE SAFETY ANALYSES	The spent fuel storage facility is designed for noncriticality by use of adequate spacing. A neutron absorber is attached to all four sides of each cell. In addition, there is a gap between individual racks and between the peripheral racks and the pool walls. These gaps form flux traps that reduces neutron movement between fuel assemblies in adjacent racks. Loading patterns maintain $k_{eff} < 0.95$ for fuel assemblies with initial nominal enrichments ≤ 5.05 weight percent Uranium-235, assuming the spent fuel pool water is unborated. The spent fuel pool storage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool, according to Figure 3.7.16-1, ensure that the k_{eff} of the spent fuel pool will always remain < 0.95 assuming the pool to be flooded with unborated water. The restrictions are consistent with the criticality safety analysis performed for the spent fuel pool, according to Figure 3.7.16-1. The restrictions on the placement of fuel assemblies within the spent fuel pool as dictated by Figure 3.7.16-1 ensure that the k_{eff} of the spent fuel pool will always be < 0.95 assuming the spent fuel pool is flooded with non-borated water. The restrictions delineated in Figure 3.7.16-1 and the Required Actions are consistent with the criticality safety analysis performed for the spent fuel pool (Ref. 1). The criticality analyses qualify the high density rack modules for storage of the fuel assemblies in one of three different loading patterns subject to certain restrictions: Mixed Zone Three Region (MZTR), Checkerboard (CB), and Homogeneous Loading (HL). Figure 3.7.16-1 provides the Category-specific burnup/enrichment limitations. Different loading

BASES

LCO (continued)

patterns may be used in different rack modules, provided each rack module contains only one loading pattern. Two different loading patterns may be used in a single rack module, subject to certain additional restrictions. The loading pattern restrictions are maintained in fuel handling administrative procedures.

MZTR is a loading pattern where fresh or low burnup assemblies (identified as Region 1 assemblies) are separated from each other and from intermediate burnup fuel assemblies (identified as Region 3 assemblies) by barrier fuel assemblies with high burnup (identified as Region 2 assemblies). CB is a loading pattern of empty cells, or cells with non-fuel bearing components, and cells with fresh or low burnup assemblies (Region 1). HL is a loading pattern of intermediate burnup fuel assemblies (Region 3). Region 2 assemblies correspond to Category A in Figure 3.7.16-1, Region 3 assemblies correspond to Category B in Figure 3.7.16-1, and Region 1 assemblies correspond to Category C in Figure 3.7.16-1.

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the spent fuel pool.

ACTIONS

A.1

When the configuration of fuel assemblies stored in the spent fuel pool is not in accordance with Figure 3.7.16-1, immediate action must be taken to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figure 3.7.16-1.

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, in either case, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Figure 3.7.16-1.

REFERENCES

1. UFSAR, Section 9.1.2.1.

B 3.7 PLANT SYSTEMS

B 3.7.17 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 environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak (LCO 3.4.13, "RCS Operational Leakage") of primary coolant at the limit of 1.0 µCi/gm (LCO 3.4.16, "RCS Specific Activity"). 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., < 20 hours).

Operating a unit at the allowable limits could result in an exclusion area boundary dose of a small fraction of the 10 CFR 100 (Ref. 1) limits, consistent with the NRC staff approved licensing basis.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break, as discussed in the UFSAR, Section 15.4 (Ref. 2) assumes the reactor has been operating with 1% defective fuel and a 1 gpm steam generator tube leak. The steam line break occurs between containment and the main steam isolation valve. Reactor coolant leakage into the steam generator continues for 9 hours until the RCS is cooled down and the pressure differential is equalized. 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 established limits, (Ref. 1) for whole body and thyroid dose.

The remaining steam generator is available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs. The Auxiliary Feedwater System supplies the necessary makeup to the steam generator. Venting continues until the reactor coolant temperature and pressure has decreased sufficiently for the Decay Heat Removal System to complete the cooldown.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 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 limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

As indicated in the Applicable Safety Analyses, the specific activity limit in the secondary coolant system of ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 maintains the radiological consequences of a Design Basis Accident (DBA) to a small fraction of Reference 1 limits.

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 due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are at low pressure 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 contributes to increased post accident doses. If secondary specific activity is not within limits, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. An isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions for 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 is based on 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. 10 CFR 100.

2. UFSAR, Section 15.4.

B 3.7 PLANT SYSTEMS

B 3.7.18 Steam Generator Level

BASES

BACKGROUND

A principal function of the steam generators is to provide superheated steam at a constant pressure (935 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 and maintenance of a constant average primary system temperature by the feedwater controls in the Integrated Control System.

The maximum operating steam generator level is based on preserving the initial condition assumptions for the steam generator inventory used in the main steam line break (MSLB) accident analysis (Ref. 1). The mass and energy release data that are input into the peak pressure analysis of the containment vessel were generated with the RELAP5/MOD2-B&W computer code. The analysis was performed with the bounding plant conditions to maximize heat generated in the Reactor Coolant System (RCS), heat transfer from the primary to secondary systems, and maximum inventory in the steam generators. Each of these conditions maximizes the mass and energy release from the MSLB. The analysis includes evaluation of the reactivity transient due to the MSLB.

For a once through steam generator, the mass inventory in a steam generator for operating at 100% power is maximized at approximately 55,000 lb.

As a steam generator becomes fouled and the operating level approaches the limit of 96%, the mass inventory in the downcomer region increases. In matching unit data of startup level versus power, the steam generator performance codes have shown 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.

However, increasing the fouling of the steam generator tube surfaces degrades the heat transfer capability of the steam generator, increases the mass inventory, and decreases the steam superheat at 100% RTP. The results were presented as the amount of mass inventory in each steam generator, in terms of the operating range level versus the steam superheat that would exist for a given inventory.

BASES

BACKGROUND (continued)

The limiting curve, which was determined from several steam generator performance code runs at a power level of 100%, conservatively bounds steam generator mass inventory value, when operating at power levels < 100%.

The points displayed in Figure 3.7.18-1 are the intercept points of the 56,000 lb mass value, at the operating range level x and steam superheat values based on a conservatively calculated mass inventory. The maximum steam generator levels specified for MODE 3 ensure that the MODE 1 MSLB analysis remains bounding.

The steam generator performance analysis also indicated 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 mixture water level should rise above the 96% upper limit, the steam superheat would tend to decrease due to reduced feedwater heating through the aspirator ports. 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 ensure 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 that would be affected by steam generator operating level is a main steam line 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 MSLB accident. A higher inventory causes the effects of the accident to be more severe. Figure 3.7.18-1 is based upon maintaining inventory in MODES 1 and 2 < 56,000 lb. It has been determined that the plant response when operating at the limit of the Figure is bounded by the MSLB analysis considering all plant effects (e.g., steam superheat and downcomer voiding).

The maximum steam generator levels specified for MODE 3 ensure that the MODE 1 MSLB analysis remains bounding. Administrative controls require determination of the boron concentration necessary to compensate for the Reactor Coolant System (RCS) cooldown that would result from a MSLB in MODE 3 from these initial levels.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The steam generator level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO is required to preserve the initial condition assumptions of the accident analyses. 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 MSLB. In addition, feedwater nozzle flooding would impair feedwater heating, and could result in excessive tube to shell temperature differentials and excessive tubesheet temperature gradients.
APPLICABILITY	In MODES 1, 2, and 3, a maximum steam generator water level is required to preserve the initial condition assumption for steam generator inventory used in the main steam line failure accident analysis (Ref. 1). In MODE 3, limits on steam generator water level, in conjunction with establishing an increased SDM, will also prevent a return to criticality in the event of an MSLB (Ref. 2). In MODES 4, 5, and 6, the water in the steam generator has a low specific enthalpy; therefore, there is no need to limit the steam generator inventory when the unit is in this condition.
ACTIONS	Prior to increasing the steam generator water level above the Low Level Limit setpoint, the ACTIONS Note alerts the Operators of the requirement to establish an increased SDM adequate to compensate for the RCS cooldown that would result from a MSLB at the elevated steam generator levels (Ref. 2). This is an exception to LCO 3.0.6 and ensures the proper actions are taken for SDM not within the required limits. <u>A.1</u> With the steam generator level in excess of the maximum limit, action must be taken to restore the level to within the bounds assumed in the analysis. To achieve this status, the water level is restored to within the limit. The 15 minute Completion Time is considered to be a reasonable time to perform this evolution. <u>B.1</u> If the water level in one or more steam generators cannot be restored to within the limits, the unit must be placed in a MODE that minimizes the

BASES

ACTIONS (continued)

B.1 (continued)

accident risk. To achieve this status, the unit must be placed 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.18.1

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 unit evolutions that can affect the steam generator level between checks. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to steam generator level status.

REFERENCES

1. UFSAR, Section 15.4.4.

2. NRC Safety Evaluation for Technical Specification Amendment 192, NRC Letter, Log No. 4424, dated October 7, 1994.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

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

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single EDG.

Offsite power is supplied to the unit switchyard from 345 kV substations at Bay Shore, Lemoyne, Hayes, and Ohio Edison - Beaver substations. During normal operation of the station, the unit auxiliary power transformer, connected to the generator isolated phase bus, provides the normal source of electrical power for station auxiliaries.

Two startup transformers are supplied from different 345 kV switchyard bus sections. Each startup transformer provides power for startup, shutdown, and post-shutdown requirements. Normally, each startup transformer is the reserve power source for one 13.8 kV bus. In event of failure of the unit auxiliary transformer supply, each 13.8 kV bus is provided with a fast transfer scheme that will automatically transfer to the pre-selected startup transformer. When power is being supplied to a 13.8 kV bus by a startup transformer, the fast transfer scheme will automatically transfer to the alternate startup transformer (if pre-selected). Reserve source selector switches are provided to pre-select the alignment.

An offsite circuit with an open phase condition can adversely impact the capability of the startup transformers to perform their function. Open Phase Protection Systems (OPPS) for the startup transformers were installed to (a) provide reasonable assurance that the OPERABLE status of offsite sources can be determined under postulated open phase conditions and (b) detect postulated open phase conditions and isolate the affected source if it is unable to perform its intended function in the event of a design basis event.

After initial installation, the OPPS will be operated with the automatic isolation function of the OPPS disabled for initial monitoring period, which is expected to last up to one operating fuel cycle. The monitoring period

BASES

BACKGROUND (continued)

will be used to confirm that the system performance and associated setpoints provide the correct level of protection.

Power supply to the 4.16 kV system is from two bus tie transformers. Each bus tie transformer normally supplies one essential and one non-essential 4.16 kV bus and is available as a reserve source for the other two 4.16 kV buses. Each essential 4.16 kV bus is provided with a fast transfer scheme that will transfer the bus from the normal source to an alternate source of power.

Two 4.16 kV essential buses, C1 and D1, provide power to ESF equipment for safe station shutdown. A detailed description of the offsite power network and the circuits to the Class 1E essential buses is found in the UFSAR, Section 8.3.1.1 (Ref. 2).

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 essential bus(es). When a Safety Features Actuation System (SFAS) actuation signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are placed in service.

The onsite standby power source for each 4.16 kV essential bus is a dedicated EDG. EDGs 1 and 2 are dedicated to essential buses C1 and D1, respectively. An EDG starts automatically on SFAS Incident Level 2 actuation or on an essential bus degraded voltage or loss of voltage signal (refer to LCO 3.3.5, "Safety Features Actuation System (SFAS) Instrumentation" and LCO 3.3.8, "Emergency Diesel Generator (EDG) Loss of Power Start (LOPS)"). After the EDG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of essential bus loss of voltage or degraded voltage, independent of or coincident with an SFAS Incident Level 2 actuation signal. The EDGs will also start and operate in the standby mode without tying to the essential bus on an SFAS Incident Level 2 actuation alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the essential bus. When the EDG is tied to the essential bus, loads are then sequentially connected to its respective essential bus by the automatic load sequencer or individual time delay relays, as applicable. The sequencing logic and individual time delay relays control the permissive and starting signals to motor breakers to prevent overloading the EDG by automatic load application.

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

BASES

BACKGROUND (continued)

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the EDG in the process. Within 35 seconds after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for EDG 1 and EDG 2 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each EDG is 2600 kW 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 essential buses are listed in Reference 2. Each EDG has its own day tank and fuel oil transfer system. The fuel oil transfer system, which includes one transfer pump, is capable of transferring fuel oil from the associated fuel oil storage tank to the day tank. Each transfer pump is capable of maintaining the level in the day tank when the associated EDG is operating a full load.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Section 6 (Ref. 4) and Section 15 (Ref. 5), 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, RCS, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

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

b. A worst-case single failure.

The AC Sources - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and separate and independent EDGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

BASES

LCO (continued)

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the essential buses.

A qualified offsite to onsite circuit consists of one 345 - 13.8 kV startup transformer, one 13.8 kV bus, one 13.8 - 4.16 kV tie transformer, and the respective circuit paths, including the nonessential bus and feeder breakers, to one 4.16 kV essential bus. Furthermore, analysis has shown that the impedances of the 345 - 13.8 kV startup transformers and the 13.8 - 4.16 kV tie transformers are such that acceptable voltage levels cannot be guaranteed for all accident scenarios and the entire station emergency loads (i.e., the essential buses) being simultaneously supplied through a single 345 - 13.8 kV startup transformer and a single 13.8 - 4.16 kV tie transformer. Thus, if both essential buses are being powered in this manner, both offsite circuits are inoperable. In addition, while not covered by this Specification, requirements for the switchyard are provided in Technical Requirements Manual 8.8.1.

In addition, in MODES 3 and 4, in lieu of one of the 345 - 13.8 kV startup transformers, one main transformer and one unit auxiliary transformer with the generator links removed (i.e., a backfeed alignment) may be used.

Each EDG must be capable of starting, accelerating to the required speed and voltage as specified in the Technical Specifications, and connecting to its respective essential bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each EDG must also be capable of accepting required loads within the assumed times, and continue to operate until offsite power can be restored to the essential buses. These capabilities are required to be met from a variety of initial conditions, such as EDG in standby with the engine hot and EDG in standby with the engine at ambient conditions. Additional EDG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the EDG to reject the single largest load. In addition, day tank fuel oil level and fuel oil transfer system requirements must be met for each EDG.

Proper sequencing of loads (which include all required individual time delay relays), including tripping of non-essential loads, is a required function for EDG OPERABILITY.

In addition, two load sequencers per train must be OPERABLE.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the EDGs, separation and independence are complete.

BASES

LCO (continued)

For the offsite AC sources, separation and independence are to the extent practical. An offsite circuit may be connected to more than one essential bus, with fast-transfer capability to the other circuit OPERABLE, and not violate separation criteria. An offsite circuit that is not connected to an essential bus is required to have OPERABLE fast-transfer interlock mechanisms to one essential bus to support OPERABILITY of that circuit. The reserve source selector switches are used to ensure this capability is available. Therefore, if both reserve source selector switches are selected to the same offsite circuit (i.e., the same startup transformer), the non-selected offsite circuit is inoperable.

APPLICABILITY

The AC sources and load sequencers are required to be OPERABLE in MODES 1, 2, 3, and 4 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 safety functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 and other conditions in which AC sources are required are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable EDG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable EDG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

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

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated EDG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power train.

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

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

b. A redundant required feature on the other train is inoperable.

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

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

The remaining OPERABLE offsite circuit and EDGs are adequate to supply electrical power to essential bus C1 and essential bus D1 of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

Consistent with Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. 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 unit safety systems. In this Condition,

BASES

ACTIONS (continued)

however, the remaining OPERABLE offsite circuit and EDGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that an EDG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable EDG.

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

a. An inoperable EDG exists; and

b. A redundant required feature on the other train is inoperable.

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

Discovering one EDG inoperable coincident with one or more inoperable redundant required support or supported features, or both, that are associated with the OPERABLE EDG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these

BASES

ACTIONS (continued)

B.2 (continued)

events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE EDG(s). If it can be determined that the cause of the inoperable EDG does not exist on the OPERABLE EDG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other EDG(s), the other EDG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable EDG cannot be confirmed not to exist on the remaining EDG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that EDG.

In the event the inoperable EDG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

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

B.4

In Condition B, the remaining OPERABLE EDG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution

BASES

ACTIONS (continued)

B.4 (continued)

System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The 7 day Completion Time is also acceptable as described in Reference 8.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These features are powered from redundant AC safety trains. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate.

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

a. All required offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

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

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

BASES

ACTIONS (continued)

C.1 and C.2 (continued)

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 EDGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

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

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

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

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

D.1 and D.2

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

BASES

ACTIONS (continued)

D.1 and D.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, 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 C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With both EDGs 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 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.

According to Regulatory Guide 1.93 (Ref. 6), with both EDGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from

BASES

ACTIONS (continued)

F.1 and F.2 (continued)

full power conditions in an orderly manner and without challenging plant systems.

G.1

One of the SFAS actions during an Incident Level 2 is to start the EDG. In the event of a loss of offsite power concurrent with an SFAS trip, the SFAS sequencer will apply emergency loads to the essential bus in accordance with the sequencer load program. Each SFAS actuation channel has two load sequencer modules.

With one or more trains with one load sequencer inoperable, the 1 hour Completion Time provides a period of time to remove the inoperable module from the SFAS cabinet. As noted, since each train is independent from the other train, separate Condition entry is allowed for inoperable load sequencers in each train.

H.1

With one or more trains with two load sequencers inoperable, the EDG cannot be loaded in the proper sequence and therefore, cannot meet its safety function. Therefore, the EDG must be immediately declared inoperable. As noted, since each train is independent from the other train, separate Condition entry is allowed for inoperable load sequencers in each train.

I.1

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

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with UFSAR, Section 8 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the EDGs are consistent with the

BASES

SURVEILLANCE REQUIREMENTS (continued)

recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 10).

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum starting output voltage of 4070 V is based on the minimum voltage value required to close the EDG output circuit breaker. The minimum steady state output voltage of 4088 V is the minimum EDG voltage setpoint value evaluated in the EDG transient analysis, which demonstrates Safety Guide 9 (Ref. 11) transient voltage criteria are satisfied. The maximum steady state output voltage of 4400 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 is no more than the maximum rated operating voltage. The minimum starting frequency value was chosen to be consistent with the minimum steady state frequency requirements. The minimum steady state output frequency of 59.5 Hz is the minimum EDG frequency value evaluated for plant-specific accident analyses, and is demonstrated by the EDG transient analysis to satisfy Safety Guide 9 (Ref. 11) transient frequency criteria. The maximum steady state output frequency of 60.5 Hz supports plant-specific analyses values.

SR 3.8.1.1

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

SR 3.8.1.2 and SR 3.8.1.8

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 1 for SR 3.8.1.2 and the Note for SR 3.8.1.8) to indicate that all EDG starts for

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.8 (continued)

these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.8 testing, the EDGs are started from standby conditions. Standby conditions for an EDG means that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, some manufacturers recommend a modified start in which the starting speed of EDGs is limited, warmup is limited to this lower speed, and the EDGs are gradually accelerated to synchronous speed prior to loading. This is the intent of Note 2, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.8 requires that, at a 184 day Frequency, the EDG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Section 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 2) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.8 applies.

Since SR 3.8.1.8 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2.

In addition to the SR requirements, the time for the EDG to reach steady state operation, unless the modified EDG start method is employed, is monitored to identify degradation of governor and voltage regulator performance.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.8 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of EDG OPERABILITY, while minimizing degradation resulting from testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

Consistent with Regulatory Guide 1.9 (Ref. 3), this Surveillance verifies that the EDGs are capable of synchronizing with the offsite electrical system and accepting loads 90% to 100% of the continuous rating of the EDG. A run time of 60 minutes ensures the engine temperatures are stabilized, while minimizing the time that the EDG is connected to the offsite source.

Although no power factor requirements are established by this SR, the EDG is normally operated at a lagging power factor between 0.8 and 0.95. The 0.8 value is the design rating of the machine, while the 0.95 is an administrative limitation. The load band is provided to avoid routine overloading of the EDG. Routine overloading may result in more frequent teardown inspections being required in order to maintain EDG reliability.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one EDG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful EDG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is within the required limit. The level is expressed as an equivalent volume in gallons, and ensures adequate fuel oil for approximately 20 hours of EDG operation at full load. This volume is also credited (in conjunction with the minimum required level in the associated storage tank) to support 7 days of EDG operation at full load.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from each fuel oil day tank once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is consistent with Regulatory Guide 1.137 (Ref. 10). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

Under accident coincident with loss of offsite power conditions loads are sequentially connected to the bus by the load sequencers and emergency time delay relays (i.e., the makeup pump relays). The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the EDGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the EDG 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 2 provides a summary of the automatic loading of essential buses.

The Frequency of 31 days is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.8.1.7

This Surveillance demonstrates that each fuel oil transfer pump (one per fuel oil transfer system) operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7 (continued)

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 fuel transfer systems are OPERABLE.

The Frequency for this SR is 92 days. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME OM Code (Ref. 12).

SR 3.8.1.9

Transfer of each 4.16 kV essential bus power supply from the unit auxiliary source (i.e., the main generator) to the pre-selected offsite circuit (i.e., pre-selected startup tarnsformer) demonstrates that if the unit auxiliary source is supplying power, the transfer circuitry to the qualified offsite circuits is OPERABLE. This ensures the capability of the offsite circuits to be properly aligned, since the unit auxiliary source is not a qualified offsite circuit. As noted (Note 1), the transfer capability is only required to be met if the unit auxiliary source is supplying the electrical power distribution subsystem. Transfer of each 4.16 kV essential bus power supply from the normal offsite circuit to the alternate offsite circuit (via the fast transfer between the two startup transformers) demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads.

The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note (Note 2). The reason for the Note is that during operation with the reactor critical, performance of the automatic transfer portion of SR 3.8.1.9.a and all of SR 3.9.1.9.b could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the automatic portion of SR 3.8.1.9.a and all of SR 3.8.1.9.b in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.10

Each EDG 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 EDG load response characteristics and capability to reject the largest single load (the high pressure injection pumps - approximately 540 kW) without exceeding a predetermined margin to the overspeed trip. This Surveillance may be accomplished by either:

a. Tripping the EDG output breaker with the EDG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load or its equivalent with the EDG solely supplying the bus.

Consistent with Safety Guide 9 (Ref. 11), 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. This corresponds to 66.75 Hz, which is 75% of the difference between synchronous speed and the overspeed trip setpoint.

The 24 month Frequency takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10 (continued)

This SR is modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Note 2 ensures that the EDG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed within the power factor limit. This power factor is representative of the actual inductive loading an EDG would see under design basis accident conditions. The power factor limit is ≤ 0.84 for EDG 1 and ≤ 0.84 for EDG 2. Under certain conditions, however, Note 2 allows the Surveillance to be conducted outside the power factor limit. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to within the limit results in voltages on the essential buses that are too high. Under these conditions, the power factor should be maintained as close as practicable to the limit while still maintaining acceptable voltage limits on the essential buses. In other circumstances, the grid voltage may be such that the EDG excitation levels needed to obtain a power factor within limit may not cause unacceptable voltages on the essential buses, but the excitation levels are in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to the power factor limit without exceeding the EDG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph C.2.2.4, this Surveillance demonstrates the operability of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the non-essential loads and energization of the essential buses and respective loads from the EDG. It further demonstrates the capability of the EDG to automatically achieve the required voltage and frequency within the specified time.

The EDG auto-start time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the EDG loading logic (i.e., the individual time delay relays for the component cooling water, service water, and makeup pumps). In certain circumstances, some of these loads can not actually be connected or loaded without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the EDG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11 (continued)

other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4.

Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

This Surveillance demonstrates that EDG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal or an SFAS actuation test signal. Noncritical automatic trips are all automatic trips except:

a. Engine overspeed; and

b. Generator differential current.

The noncritical trips are bypassed during DBAs and provide alarms on abnormal engine conditions. These alarms provide the operator with sufficient time to react appropriately. The EDG 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 EDG.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required EDG from service. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12 (continued)

surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

Consistent with IEEE 387-1995 (Ref. 13), this Surveillance demonstrates the EDGs can start and run continuously at full load capability (90% to 100% of the EDG continuous rating) for an interval of not less than 8 hours, ≥ 2 continuous hours of which is at a load equivalent to 105% to 110% of the continuous rating and the remainder of the time at a load equivalent to 90% to 100% of the continuous rating of the EDG. The EDG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the EDG. Routine overloading may result in more frequent teardown inspections, in accordance with vendor recommendations, in order to maintain EDG OPERABILITY.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13 (continued)

cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Note 3 ensures that the EDG is tested under load conditions that are consistent with Regulatory Guide 1.9 (Ref. 3) for the 2-hour portion of the test and are as close to design conditions as possible for the 6-hour portion of the test. When synchronized with offsite power, testing should be performed within the power factor limit. This power factor is representative of the actual inductive loading an EDG would see under design basis accident conditions. When an EDG is tested at a load equivalent to 105% to 110% of the continuous rating (part a), the power factor limit is $\leq$ 0.90. When an EDG is tested at a load equivalent to 90% to 100% of the continuous rating (part b), the power factor limit is ≤ 0.84 for EDG 1 and ≤ 0.84 for EDG 2. Under certain conditions, however, Note 3 allows the Surveillance to be conducted outside the power factor limit. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to within the limit results in voltages on the essential buses that are too high. Under these conditions, the power factor should be maintained as close as practicable to the limit while still maintaining acceptable voltage limits on the essential buses. In other circumstances, the grid voltage may be such that the EDG excitation levels needed to obtain a power factor within limit may not cause unacceptable voltages on the essential buses, but the excitation levels are in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to the power factor limit without exceeding the EDG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 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 24 month Frequency is based on engineering judgment and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the EDG. Routine overloads may result in more frequent teardown inspections, in accordance with vendor recommendations, in order to maintain EDG OPERABILITY. The requirement that the diesel has operated for at least 1 hour at approximately full load conditions prior to performance of this Surveillance is based on achieving hot, stabilized conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all EDG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.15

In the event of a DBA coincident with a loss of offsite power, the EDGs 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 EDG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an SFAS actuation signal. For this test, the EDG loading logic includes both the load sequencer and the individual time delay relays for the makeup pumps. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the EDG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for EDGs. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Section 8.3.1.1.
3. Regulatory Guide 1.9, Rev. 3.
4. UFSAR, Section 6.
5. UFSAR, Section 15.
6. Regulatory Guide 1.93, Rev. 0, December 1973.
7. Generic Letter 84-15.
8. NRC Safety Evaluation for Amendment 206, dated February 26, 1996.
9. UFSAR, Section 8.
10. Regulatory Guide 1.137, Rev. 1, October 1979.
11. Safety Guide 9, March 10, 1971.
12. ASME Code for Operation and Maintenance of Nuclear Power Plants.
13. IEEE 387-1995.

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 LCO 3.8.1, "AC Sources - Operating."
APPLICABLE SAFETY ANALYSES	The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident. In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst-case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems. During MODES 1, 2, 3, and 4 various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown MODES based on:

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration;

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both;

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems; and

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite emergency diesel generator (EDG) power.

AC Sources - Shutdown satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE EDG, associated with a distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and EDG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the essential bus(es).

A qualified offsite to onsite circuit consists of either one 345 - 13.8 kV startup transformer or one main transformer and one unit auxiliary transformer with the generator links removed (i.e., in backfeed alignment), one 13.8 kV bus, one 13.8 - 4.16 kV tie transformer, and the respective circuit path, including the non-essential bus and feeder breakers, to one 4.16 kV essential bus.

BASES

LCO (continued)

The EDG must be capable of starting, accelerating to the required speed and voltage as specified in the Technical Specifications, and connecting to its respective essential bus on detection of bus undervoltage (loss of voltage or degraded voltage). This sequence must be accomplished within 10 seconds. The EDG must be capable of accepting required shutdown loads (shutdown loads are started through individual time delay relays), and must continue to operate until offsite power can be restored to the essential buses. These capabilities are required to be met from a variety of initial conditions such as EDG in standby with the engine hot and EDG in standby at ambient conditions.

Proper sequencing of loads, including tripping of non-essential loads, is a required function for EDG OPERABILITY.

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

A.1

An offsite circuit would be considered inoperable if it were not available to one required train. If two trains are required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of irradiated fuel movement. By the allowance of the option to declare features inoperable with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required EDG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend movement of irradiated fuel assemblies and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) specified in LCO 3.1.1, "Shutdown Margin (SDM)," or boron concentration (MODE 6) specified in LCO 3.9.1, "Boron Concentration." Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the Reactor Coolant System (RCS) for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive moderator temperature coefficient (MTC) must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of 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 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 should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3 (continued)

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required essential bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.9 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.6 and SR 3.8.1.15 are not required to be met because the Safety Features Actuation System (SFAS) actuation signal is not required to be OPERABLE.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE EDG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V essential bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the EDG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the EDG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each emergency diesel generator (EDG) is provided with storage tanks having a fuel oil capacity sufficient to operate that diesel for a period of 7 days while the EDG is supplying maximum post loss of coolant accident load demand discussed in the UFSAR, Section 8.3.1 (Ref. 1). The maximum load demand is calculated using the assumption that at least two EDGs are available. This onsite fuel oil capacity is sufficient to operate the EDGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from the storage tank to the day tank by a submersed transfer pump inside each storage tank. Each storage tank is installed above grade elevation.

For proper operation of the standby EDGs, it is necessary to ensure the proper quality of the fuel oil. While Davis-Besse is not committed to this Regulatory Guide, Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The EDG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated EDG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump normally contains an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each EDG has an air start system with two air start receivers per subsystem, and each air start receiver has adequate capacity for five successive start attempts on the EDG without recharging the air start receiver.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 4) and Section 15 (Ref. 5), assume Engineered Safety Features (ESF) systems are OPERABLE. The EDGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of EDGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. EDG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air subsystem is required to have a minimum capacity for five successive EDG start attempts without recharging the air start receivers. Thus, only one of the two air start receivers for each EDG is required to be OPERABLE.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated EDG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each EDG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable EDG subsystem. Complying with the Required Actions for one inoperable EDG subsystem may allow for continued operation, and subsequent inoperable EDG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for an EDG is not available. However, the Condition is restricted to fuel oil level reductions, that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations which may

BASES

ACTIONS

A.1 (continued)

be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the EDG inoperable. This period is acceptable based on the remaining capacity (≥ 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < 260 gal, sufficient lube oil to support 7 days of continuous EDG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the EDG inoperable. This period is acceptable based on the remaining capacity (≥ 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated EDG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the EDG fuel oil.

BASES

ACTIONS (continued)

D.1

If the test results for the new fuel oil properties defined in the Bases for SR 3.8.3.3 that are not required to be obtained prior to addition of the new fuel oil to the storage tanks are not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if an EDG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the EDG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < 210 psig in the required air start receiver, sufficient capacity for five successive EDG start attempts does not exist. However, as long as the receiver pressure is ≥ 139 psig, there is adequate capacity for at least one start attempt, and the EDG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the EDG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most EDG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or one or more EDGs with fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated EDG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each EDG's operation for 7 days at full load. Credit for the minimum required level in the associated day tank (4000 gallons per SR 3.8.1.4) is being taken to support the 7 days of EDG operation. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

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

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each EDG. The 260 gal requirement is based on the EDG manufacturer consumption values for the run time of the EDG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the EDG, when the EDG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since EDG starts and run time are closely monitored by the unit staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-06 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.825 and ≤ 0.876 or an API gravity at 60°F of ≥ 30° and ≤ 40° when tested in accordance with ASTM D1298-85 (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-86 or a water and sediment content within limits when tested in accordance with the test specified in ASTM D975-06 (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-06 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-06 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D4294-90 (Ref. 6). 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 EDG operation. This Surveillance ensures the availability of high quality fuel oil for the EDGs.

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.

Particulate concentrations should be determined in accordance with ASTM D2276-88 (Ref. 6). The total particulate concentration in the fuel oil has a limit of 10 mg/l.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each EDG is available. The system design requirements for each air start receiver provide for a minimum of five engine start cycles without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished using only one of the two air start receivers for each EDG.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.4 (continued)

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

REFERENCES

1. UFSAR, Section 8.3.1.
2. Regulatory Guide 1.137.
3. ANSI N195-1976, Appendix B.
4. UFSAR, Section 6.
5. UFSAR, Section 15.
6. ASTM Standards: D4057-95; D975-06; D1298-85; D4176-86; D4294-90; D2276-88.
7. ASTM Standards, D975-06, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 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 and preferred AC vital bus power (via inverters). 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 recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125/250 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power sources (Train 1 and Train 2). Each source consists of two 125 VDC batteries, one battery charger for each battery, and all the associated control equipment and interconnecting cabling.

The 250 VDC source is obtained by use of the two 125 VDC batteries connected in series. Additionally, there is one spare battery charger per train, which provides backup service in the event that one of the two preferred battery chargers is out of service. If the spare battery charger is substituted for one of the two preferred battery chargers, then the requirements of independence and redundancy between sources are maintained.

During normal operation, the 125/250 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.

The Train 1 and Train 2 DC electrical power sources provide the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. The DC electrical power sources also provide DC electrical power to the inverters, which in turn power the 120 VAC vital buses.

The DC electrical power distribution system is described in more detail in Bases for LCO 3.8.9, "Distributions System - Operating," and for LCO 3.8.10, "Distribution Systems - Shutdown."

Each set of 125/250 VDC batteries is separately housed in a ventilated room apart from its charger and distribution centers. Each source is located in an area separated physically and electrically from the other

BASES

BACKGROUND (continued)

source to ensure that a single failure in one source does not cause a failure in a redundant source. There is no sharing between redundant Class 1E sources, such as batteries, battery chargers, or distribution panels.

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the UFSAR, Section 8 (Ref 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train 1 and Train 2 DC electrical power sources 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. The minimum design voltage limit is established in the DC System Analysis.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. Optimal long term performance is obtained by maintaining a float voltage 2.17 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge.

Each Train 1 and Train 2 DC electrical power source battery charger 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 also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 12 hours while supplying normal steady state loads discussed in the UFSAR, Section 8 (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have nominal recharge efficiencies of greater than 95%,

BASES

BACKGROUND (continued)

so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 5) and Section 15 (Ref. 6), assume that Engineered Safety Features (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the EDGs, 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 unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

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

b. A worst-case single failure.

The DC Sources - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power sources (Train 1 and Train 2), each train consisting of two batteries, one battery charger for each battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power source does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power source requires two batteries and one charger per battery to be operating and connected to the associated DC bus(es).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

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

BASES

APPLICABILITY (continued)

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

The DC electrical power source requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

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

Condition A represents one train with one or two required battery chargers inoperable. The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the

BASES

ACTIONS

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

amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable required battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger, use of an inoperable, but functional Class 1E battery charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1

Condition B represents one train with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power sources is inoperable for reasons other than Condition A (e.g., one or both batteries in a train inoperable), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical sources to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function

BASES

ACTIONS

B.1 (continued)

of the inoperable DC electrical power source and, if the DC electrical power source is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1 and C.2

If the inoperable DC electrical power source cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support 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 and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC source. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (130.2 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

This SR verifies the required design capacity of the required battery chargers. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is recommended 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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued

charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 475 amps at the minimum established float voltage for 8 hours. The ampere requirements are also well within the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 8 hours.

The other option requires that each required battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps.

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.

SR 3.8.4.3

A battery service test is a special test of the battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations, or at some other outage, with intervals between tests not to exceed 24 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1971.
4. UFSAR, Section 8.
5. UFSAR, Section 6.
6. UFSAR, Section 15.
7. Regulatory Guide 1.93, December 1974.
8. IEEE-450-1995.
9. Regulatory Guide 1.32, August 1972.
10. Regulatory Guide 1.129, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 1) and Section 15 (Ref. 2), assume that Engineered Safety Features (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the EDGs, 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 the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident. In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many DBAs that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC Sources - Shutdown satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One train of the DC electrical power sources consisting of two batteries, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, is required to be OPERABLE to support one train of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The DC electrical power source required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

BASES

APPLICABILITY (continued)

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

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

With the required train of DC electrical power sources inoperable, the minimum required DC electrical power source is not available. Therefore, suspension of movement of irradiated fuel assemblies and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6) is required. Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the Reactor Coolant System (RCS) for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive Moderator Temperature Coefficient (MTC) must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power source and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit 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 source should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Section 6.

2. UFSAR, Section 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND	This LCO delineates the limits on battery float current as well as cell electrolyte temperature, level, and float voltage for the DC electrical power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.16 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications" (Ref. 1). The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. Optimal long term performance is obtained by maintaining a float voltage 2.17 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge.
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 2) and Section 15 (Ref. 3), assume Engineered Safety Features systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the EDGs, emergency auxiliaries, and control and switching during all MODES of operation. The specific Applicable Safety Analyses for the DC Electrical Power System are provided in the Bases for LCO 3.8.4 and LCO 3.8.5. Battery parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC Electrical Power System function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.16.

BASES

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power sources. Therefore, battery parameter limits are only required when the DC electrical power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one or more batteries ≤ 2.07 V, the battery cell is degraded. Within 2 hours, verification of the required battery charger OPERABILITY is required by monitoring the battery terminal voltage (SR 3.8.4.1) and verification of the overall battery state of charge is required by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries ≤ 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1 and B.2

One or more batteries with float current > 2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours, verification of the required battery charger OPERABILITY is required by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. If the charger is operating in the current limit mode after 2 hours, that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

BASES

ACTIONS

B.1 and B.2 (continued)

If the float voltage is found to be satisfactory there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not an indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

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

With one or more batteries with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.16, "Battery Monitoring and Maintenance Program"). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours, level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.16.b requirement to initiate action to equalize and test in accordance with manufacturer's

BASES

ACTIONS

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

recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the batteries may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With batteries in redundant trains with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one train within 2 hours.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, or failure of SR 3.8.6.6, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one train with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 1). The 7 day Frequency is more conservative than the recommendations of IEEE-450 (Ref. 1).

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 130.2 V at the battery terminals, or 2.17 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.16. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are greater than the short term absolute minimum voltage of 2.07 V. The Frequencies for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell are consistent with IEEE-450 (Ref. 1).

SR 3.8.6.3

The minimum established design limit specified for electrolyte level (greater than the minimum level indication mark) ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 1).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 1).

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test as specified in IEEE-450 (Ref. 1).

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance discharge test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 4). These references recommend that the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

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. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's ratings. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is below 90% of the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. IEEE-450-1995.

2. UFSAR, Section 6.

3. UFSAR, Section 15.

4. IEEE-485-1983, June 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND	The inverters are the preferred source of power for the 120 VAC vital buses because of the stability and reliability they achieve. The function of each inverter is to provide AC electrical power to the associated 120 VAC vital bus. The inverters can be powered from an internal AC source/rectifier or from the station battery. Four rectifiers are provided to supply normal DC power to the four essential inverters. Each rectifier output is connected in parallel with the DC panel reserve supply to the inverter. The output voltage of the rectifier is maintained higher than the station battery voltage, which reverse-biases a coupling diode to prevent current flow from the reserve supply, and to prevent back-feeding of the DC system. The failure of the rectifier AC source and/or of the rectifier itself will forward bias the coupling diode, and cause the battery and/or battery charger to become the DC source to the essential inverter with no power interruption. The inverter provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Safety Features Actuation System (SFAS). Specific details on inverters and their operating characteristics are found in UFSAR, Section 8.3 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 2) and Section 15 (Ref. 3), assume Engineered Safety Features systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and SFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems. The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required 120 VAC vital buses 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 are a part of the electrical power distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The inverters ensure the availability of 120 VAC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and SFAS instrumentation and controls is maintained. The four inverters (two per train) ensure an uninterruptible supply of AC electrical power to the 120 VAC vital buses even if the 4.16 kV essential buses are de-energized.

OPERABLE inverters require the associated 120 VAC vital bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 VDC station battery. Alternatively, power supply may be from an AC source or battery charger via rectifier as long as the station battery is available as the uninterruptible power supply.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Inverter requirements for MODES 5 and 6 and other conditions in which inverters are required are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

A.1

With a Train 1 or Train 2 inverter inoperable, its associated 120 VAC vital bus becomes inoperable unless it is energized from its Class 1E constant voltage transformer. LCO 3.8.9, "Distribution Systems - Operating," addresses this action however, pursuant to LCO 3.0.6, this action would not have to be entered even if the 120 VAC vital bus were de-energized. For this reason, a Note has been included in Condition A requiring entry into the Conditions and Required Actions of LCO 3.8.9. This ensures that proper action for a de-energized 120 VAC vital bus is taken.

BASES

ACTIONS

A.1 (continued)

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. 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 unit 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 120 VAC vital bus is powered from its Class 1E constant voltage transformer, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120 VAC vital buses is the preferred source for powering instrumentation trip setpoint devices.

B.1

With two inverters in the same train inoperable, the remaining inverters are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in one of the two remaining inverters could result in the minimum ESF functions not being supported. Therefore, one of the inverters must be restored to OPERABLE status within 8 hours.

The 8 hour Completion Time is consistent with that allowed for an inoperable train of 120 VAC vital buses.

C.1 and C.2

If the inoperable Train 1 or Train 2 inverters cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and 120 VAC vital buses energized from the associated inverter. Each inverter may be connected to its associated rectifier as long as the battery is available as the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1 (continued)

uninterruptible power supply. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and SFAS connected to the 120 VAC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. UFSAR, Section 8.3.
2. UFSAR, Section 6.
3. UFSAR, Section 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 1) and Section 15 (Ref. 2), assume Engineered Safety Features 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 Reactor Protection System and Safety Features Actuation System (SFAS) instrumentation and controls so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of one inverter to a required 120 VAC vital bus during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident. In general, when the unit is shut down, the Technical Specification requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many DBAs that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The inverters were previously identified as part of the electrical power distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The required inverter provides an essential supply of AC electrical power to the 120 VAC vital bus. OPERABILITY of the inverter requires the associated 120 VAC vital bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 VDC station battery. Alternately, power supply may be from an AC Source or battery charger via rectifier as long as the station battery is available as the uninterruptible power supply. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The inverter required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

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

With the required inverter inoperable, suspension of movement of irradiated fuel assemblies and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) specified in LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," or boron concentration (MODE 6) specified in LCO 3.9.1, "Boron Concentration," is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive moderator temperature coefficient (MTC) must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverter and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverter should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a Class 1E constant voltage transformer or non-essential power source.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the required inverter is functioning properly with all required circuit breakers closed and 120 VAC vital bus energized from the inverter. The inverter may be connected to its associated rectifier as long as the battery is available as the uninterruptible power supply. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the 120 VAC vital bus. The 7 day Frequency takes into account the other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. UFSAR, Section 6.

2. UFSAR, Section 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and 120 VAC vital bus electrical power distribution subsystems.

The AC electrical power subsystem for each train consists of a primary 4.16 kV essential bus and secondary 480 and 120 V buses, distribution panels, motor control centers and load centers. Each 4.16 kV essential bus has at least one separate and independent offsite source of power as well as a dedicated onsite emergency diesel generator (EDG) source. Each 4.16 kV essential bus is normally connected to a preferred offsite source. After a loss of the preferred offsite power source to a 4.16 kV essential bus, a fast transfer to the alternate offsite source is accomplished. If all offsite sources are unavailable, the onsite EDG supplies power to the 4.16 kV essential bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

The AC electrical power distribution subsystem for each train includes the safety related buses shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E constant voltage source transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters - Operating." Each constant voltage source transformer is powered from a Class 1E AC bus.

The DC electrical distribution subsystem for each train consists of a 250/125 VDC motor control center (MCC), and each 250/125 VDC MCC consists of two 125 VDC buses.

The list of all required DC and AC vital distribution buses is presented in Table B 3.8.9-1.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 1) and Section 15 (Ref. 2), assume Engineered Safety Features (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits," Section 3.4, "Reactor Coolant System (RCS)," and Section 3.6, "Containment Systems."

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power 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 distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE. However, the 250 VDC portion of the buses listed in Table B 3.8.9-1 power non-essential loads and are not required to be OPERABLE.

Maintaining the Train 1 and Train 2 AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF systems is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE AC vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter, via inverted 125 VDC voltage or Class 1E constant voltage transformer.

BASES

LCO (continued)

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.9-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.9 is required. Some buses, such as distribution panels and motor control centers, which help comprise the AC and DC distribution systems, are not listed in Table B 3.8.9-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.9-1 (e.g., a breaker supplying a single distribution panel fails open), the individual loads on the bus would be declared inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.9-1 (e.g., loss of 4.16 kV essential bus, which results in de-energization of all buses powered from the 4.16 kV essential bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV essential bus).

In addition, tie breakers and disconnect switches between redundant safety related AC, DC, and AC vital bus electrical power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers or disconnect switches are closed, the electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystem) are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV essential buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 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

BASES

APPLICABILITY (continued)

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

Electrical power distribution subsystem requirements for MODES 5 and 6 and other conditions in which electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more Train 1 and Train 2 required AC electrical power distribution subsystems (except AC vital buses), inoperable and a loss of function has not occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC electrical power distribution subsystem(s) must be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated EDG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

Required Action A.1 is modified by a Note that requires the applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," to be entered for DC sources made inoperable by inoperable power distribution subsystems. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. Inoperability of a distribution system can result in loss of charging power to batteries and

BASES

ACTIONS

A.1 (continued)

eventual loss of DC power. This Note ensures that the appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

B.1

With one or more AC vital buses inoperable, and a loss of function has not yet occurred, 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 8 hours by powering the bus from the associated inverter, via inverted 125 VDC voltage or Class 1E constant voltage transformer.

Condition B represents one or more AC vital buses without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected vital bus.

This 8 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 8 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

BASES

ACTIONS

B.1 (continued)

The 8 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.

C.1

With one DC electrical power distribution subsystem inoperable, and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystem is 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 subsystem could result in the minimum required ESF functions not being supported. Therefore, the DC electrical power distribution subsystem must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one DC electrical power distribution subsystem without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions to restore power to the affected train; and

BASES

ACTIONS

C.1 (continued)

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one inoperable electrical power distribution subsystem results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker (which includes all types of circuit breaking devices) alignment. The correct breaker alignment, including tie breakers open between redundant buses, ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions. The voltage of the DC bus must be greater than or equal to 125 VDC.

BASES

REFERENCES

1. UFSAR, Section 6.
2. UFSAR, Section 15.
3. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN 1*	TRAIN 2*
AC essential buses	4160 V 480 V	Essential Bus C1 Essential Bus E1	Essential Bus D1 Essential Bus F1
DC buses	250/125 V	DC MCC1	DC MCC2
AC vital buses	120 V	Bus Y1 Bus Y3	Bus Y2 Bus Y4

* Each train of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND	A description of the AC, DC and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Section 6 (Ref. 1) and Section 15 (Ref. 2), assume Engineered Safety Features (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident. The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical power distribution system necessary to support OPERABILITY of required systems, equipment, and components - all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

BASES

LCO (continued)

OPERABLE AC vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage either from a) the associated inverter, via inverted 125 VDC voltage or the Class 1E constant voltage transformer, or b) the associated non-essential power source (regulated instrumentation distribution panel YAR or YBR). Furthermore, tie breakers between redundant safety related AC, DC, and AC vital buses are allowed to be closed.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents.

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystem requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

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

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of irradiated fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystems LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend movement of irradiated fuel assemblies and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) specified in LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," or boron concentration (MODE 6) specified in LCO 3.9.1, "Boron Concentration"). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive moderator temperature coefficient (MTC) must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required decay heat removal (DHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.3 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the DHR ACTIONS would not be entered. Therefore, Required Action A.2.4 is provided to direct declaring DHR inoperable, which results in taking the appropriate DHR actions.

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

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 safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution subsystems are functioning properly, with the correct breaker (which includes all types of circuit breaking devices) alignment. The verification of proper voltage availability on the required buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these required buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions. The voltage of the required DC bus must be greater than or equal to 125 VDC.

REFERENCES

1. UFSAR, Section 6.
2. UFSAR, Section 15.

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) and the refueling canal during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of the volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets 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 COLR. The COLR specifies the boron concentration limit reactivity requirements with the actual boron concentration necessary to achieve the requirements disseminated to Operations by memorandum. This approach is consistent with License Amendment 207. Unit 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 unit procedures.

UFSAR, Appendix 3D.1.22, 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 Makeup and Purification System 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 and removed, the refueling canal is then flooded with borated water from the borated water storage tank into the open reactor vessel by gravity feeding or by the use of a Decay Heat Removal (DHR) System pump.

The pumping action of the DHR System in the RCS, and the natural circulation due to thermal driving heads in the reactor vessel, 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, "DHR and Coolant Circulation - High Water Level," and LCO 3.9.5, "DHR and Coolant Circulation - Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS and the refueling canal above the COLR limit.

BASES

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) and includes an uncertainty allowance.

The required boron concentration and the unit refueling procedures that demonstrate 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.

During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS 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 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, "SHUTDOWN MARGIN (SDM)," and LCO 3.1.2, "Reactivity Balance," ensure that an adequate amount of negative reactivity is available to shut down the reactor and to maintain it subcritical.

The Applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling canal when this volume is connected to the RCS. When the refueling canal is isolated from the RCS, no potential path for boron dilution exists.

ACTIONS

A.1

Continuation of positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant

BASES

ACTIONS

A.1 (continued)

volume in the RCS or the refueling canal is less than its limit, all operations involving positive reactivity additions must be suspended immediately.

Suspension of positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g., temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.2

In addition to immediately suspending positive reactivity additions, action to restore the concentration must be initiated immediately.

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 operator should begin boration with the best source available for unit conditions.

Once action has been 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.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures the coolant boron concentration in the RCS, and connected portions of the refueling canal is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to re-connecting portions of the refueling canal to the RCS, this SR must be met per SR 3.0.4. If any dilution activity has occurred while the canal was disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

The SR 3.9.1.1 Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

BASES

REFERENCES

1. UFSAR, Appendix 3D.1.22, Criterion 26 – Reactivity Control System Redundancy and Capability.

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 Reactor Protection System (RPS) and Post Accident Monitoring (PAM) Instrumentation. These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The use of portable detectors is permitted, provided the LCO requirements are met. The installed RPS source range neutron flux monitors are two high sensitivity proportional counters (BF_3 chambers). The detectors monitor the neutron flux in counts per second. The instrument range covers seven decades of neutron flux (1E-1 cps to 1E+6 cps). The detectors also provide continuous visual indication in the control room to alert operators to a possible dilution accident. The RPS is designed in accordance with the criteria presented in Reference 1. The installed PAM monitors are two safety grade electrically and physically independent fission chamber strings. The channel 1 PAM detector (NI5874A) is located near the corresponding channel 1 RPS detector (NI-2) and the channel 2 PAM detector (NI5875A) is located adjacent to the corresponding channel 2 RPS detector (NI-1). The detectors monitor the neutron flux in counts per second. The PAM instrument range covers six decades of neutron flux (1E-1 cps to 1E+5 cps). The detectors also provide continuous visual indication in the control room and an audible indication to alert operators. If used, portable detectors should be functionally equivalent to the installed source range monitors.
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. The safety analysis of the boron dilution accident is described in Reference 2. The analysis of the boron dilution accident shows that the normally available SDM would not be lost, and there is sufficient time for the operator to take corrective action. The source range neutron flux monitors have no safety function are not assumed to function during any UFSAR design basis accident or transient analysis. However, the source range neutron channels provide on scale monitoring of neutron flux levels during refueling conditions. Therefore, they are being retained in Technical Specifications.

BASES

LCO

This LCO requires two source range neutron flux monitors to be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each monitor must provide continuous visual indication in the control room, and one monitor must provide audible indication in the containment and the control room.

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 RPS source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.9, "Source Range Neutron Flux." In MODES 1, 2, and 3, these same installed PAM source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.17, "Post Accident Monitoring (PAM) Instrumentation."

ACTIONS

A.1 and A.2

With only one required source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, positive reactivity additions and introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no required source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no required source range neutron flux monitor OPERABLE, there is no direct means of detecting changes in core reactivity. However, since positive reactivity additions are not to be made, the core reactivity

BASES

ACTIONS

B.2 (continued)

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 ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and 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.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. 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.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the RPS source range channel is a complete check and re-adjustment of the channels, from the preamplifier input to the indicators, and for the PAM source range channels is a complete check of the instrument channel. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. UFSAR, Appendices 3D.1.9, Criterion 13 – Instrumentation and Control; 3D.1.16, Criterion 20 – Protection Systems Functions; 3D.1.17, Criterion 21 – Protection System Reliability and Testability; 3D.1.18, Criterion 22 – Protection System Independence; 3D.1.19, Criterion 23 – Protection System Failure Modes; 3D.1.20, Criterion 24 – Separation of Protection and Control Systems; and 3D.1.25, Criterion 29 – Protection Against Anticipated Operational Occurrences.

2. UFSAR, Section 15.2.4 and Appendix 4B.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Decay Time

BASES

BACKGROUND	The movement of irradiated fuel assemblies within the reactor pressure vessel requires that the reactor be subcritical for ≥ 72 hours. This ensures sufficient time has elapsed to allow the radioactive decay of the short lived fission products.
APPLICABLE SAFETY ANALYSES	Prior to movement of irradiated fuel assemblies within the reactor vessel, the reactor must be subcritical for ≥ 72 hours. This time period is an initial assumption of the fuel handling accident in containment (Ref. 1) postulated by Regulatory Guide 1.25 (Ref. 2). The minimum time period of 72 hours ensure sufficient time has elapsed to allow the radioactive decay of the short lived fission products, which helps ensure that the offsite doses during a fuel handling accident will be within the 10 CFR 100 limits, as provided by the guidance of Reference 3. Decay Time satisfies Criterion 2 of 10 CFR 50.36(d)(2)(ii).
LCO	The reactor is required to be subcritical for ≥ 72 hours to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits as provided by 10 CFR 100.
APPLICABILITY	LCO 3.9.3 is applicable when moving irradiated fuel assemblies within the reactor pressure vessel. The LCO ensures that the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis cannot occur.
ACTIONS	A.1 With the reactor not subcritical for ≥ 72 hours, all operations involving movement of irradiated fuel assemblies within the reactor pressure vessel shall be suspended immediately to ensure that a fuel handling accident in containment cannot occur. The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.3.1 Verification that the reactor has been subcritical for ≥ 72 hours ensures that the design basis decay time assumption for the postulated fuel handling accident analysis in containment is met.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1 (continued)

The Frequency of prior to movement of irradiated fuel assemblies within the reactor pressure vessel ensures that the 72 hour limit is met prior to commencement of irradiated fuel movement within the reactor pressure vessel.

REFERENCES

1. UFSAR, Section 15.4.7.3.
2. Regulatory Guide 1.25, March 23, 1972.
3. 10 CFR 100.10.

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 UFSAR, Appendix 3D.1.30 (Ref. 1), 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. 2). Heat is removed from the RCS by circulating reactor coolant through the DHR coolers, where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the core flood nozzles. 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 coolers. 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 ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit the DHR pump to be removed from operation for short durations under the condition that the boron concentration is not diluted. This conditional stopping of the DHR pump does not result in a challenge to the fission product barrier. The DHR System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	Only one DHR loop is required for decay heat removal in MODE 6, with a water level ≥ 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:

BASES

LCO (continued)

a. Removal of decay heat; and

b. Mixing of borated coolant to minimize the possibility of criticality.

An OPERABLE DHR loop includes a DHR pump, a cooler, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in one of the RCS hot legs and is returned to the core flood nozzles.

Additionally, since the DHR System is a manually operated system (i.e., it is not automatically actuated), each DHR loop is OPERABLE if it can be manually aligned (remote or local) to the decay heat mode.

The LCO is modified by a Note that allows the required DHR loop to be removed from operation for up to 1 hour in an 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration by introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1, "Boron Concentration." Boron concentration reduction with coolant at boron concentrations less than required to assure the RCS boron concentration is maintained is prohibited because uniform concentration distribution cannot be ensured without forced circulation. 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 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling canal.

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 ft water level was selected because it corresponds to the 23 ft 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 (RCS). DHR loop requirements in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, are located in LCO 3.9.5, "Decay Heat Removal (DHR) 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.

BASES

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. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

A.2

If DHR loop requirements are not met, actions shall be taken immediately to suspend the loading of irradiated fuel assemblies in the core. 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 immediately in order to satisfy DHR loop requirements.

A.4, A.5, and A.6

If no DHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts;

b. One door in each air lock must be closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by a Containment Purge and Exhaust Isolation System. A Containment Purge and Exhaust Isolation System consists of a containment purge and exhaust noble

BASES

ACTIONS

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

gas monitor, including all automatic actuations resulting from a high radiation signal (i.e., the shutting down of the containment purge and exhaust supply and exhaust fans and closure of the associated inlet and outlet dampers), and one containment purge and exhaust isolation valve in each penetration flow path, which is capable of being manually closed from the control room.

With DHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions stated above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most DHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the DHR loop is in operation and circulating reactor coolant. The flow rate (i.e., ≥ 2800 gpm) 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.

REFERENCES

1. UFSAR, Appendix 3D.1.30, Criterion 34 – Residual Heat Removal.

2. UFSAR, Section 9.3.5.

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 UFSAR, Appendix 3D.1.30 (Ref. 1), 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. 2). Heat is removed from the RCS by circulating reactor coolant through the DHR coolers, where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the core flood nozzles. 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 coolers. 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. The DHR System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, two independent DHR loops must be OPERABLE. Additionally, one DHR loop must be in operation to provide: a. Removal of decay heat; and b. Mixing of borated coolant to minimize the possibility of criticality. This LCO is modified by two Notes. Note 1 permits the DHR pumps to be removed from operation for ≤ 15 minutes when switching from one train to another. The circumstances for stopping both DHR pumps are to be limited to situations when the outage time is short and the core outlet

BASES

LCO (continued)

temperature is maintained > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations by introduction of coolant into the RCS with boron concentrations less than required to meet the minimum boron concentration of LCO 3.9.1, "Boron Concentration," when DHR forced flow is stopped.

Note 2 allows one DHR loop to be inoperable for a period of 2 hours provided the other loop is OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include time to core boiling, potential for RCS draindown, and RCS makeup capability. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

An OPERABLE DHR loop consists of a DHR pump, a cooler, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in one of the RCS hot legs and is returned to the core flood nozzles.

Additionally, since the DHR System is a manually operated system (i.e., it is not automatically actuated), each DHR loop is OPERABLE if it can be manually aligned (remote or local) to the decay heat removal mode.

APPLICABILITY

Two DHR loops are required to be OPERABLE, and one in operation in MODE 6, with the water level < 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 (RCS)." DHR loop requirements in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, are located in LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation - High Water Level."

ACTIONS

A.1 and A.2

With fewer than the required loops OPERABLE, action shall be immediately initiated and continued until the DHR loop is restored to OPERABLE status or until ≥ 23 ft of water level is established above the reactor vessel flange. 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, and only one DHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions to restore the required forced circulation or water level.

BASES

ACTIONS (continued)

B.1

If no DHR loop is in operation or no DHR loop is OPERABLE, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

B.2

If no DHR loop is in operation or no DHR loop is OPERABLE, actions shall be initiated immediately, and continued, 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.

If no DHR loop is OPERABLE or in operation, alternate actions shall have been initiated immediately under Condition A to establish ≥ 23 ft of water above the top of the reactor vessel flange. Furthermore, when the LCO cannot be fulfilled, alternate decay heat removal methods, as specified in the unit's Abnormal and Emergency Operating Procedures, should be implemented. This includes decay heat removal using the high pressure injection, makeup, or other injection sources, 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 unit conditions. The choice could be different if the reactor vessel head is in place rather than removed.

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

If no DHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with four bolts;

b. One door in each air lock must be closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or

BASES

ACTIONS

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

verified to be capable of being closed by a Containment Purge and Exhaust Isolation System. A Containment Purge and Exhaust Isolation System consists of a containment purge and exhaust noble gas monitor, including all automatic actuations resulting from a high radiation signal (i.e., the shutting down of the containment purge and exhaust supply and exhaust fans and closure of the associated inlet and outlet dampers), and one containment purge and exhaust isolation valve in each penetration flow path, which is capable of being manually closed from the control room.

With DHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions stated above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most DHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one DHR loop is in operation. The flow rate (i.e., ≥ 2800 gpm) 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, 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.

SR 3.9.5.2

Verification that the required pump is OPERABLE ensures that an additional DHR pump 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 pump. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.2 (continued)

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES

1. UFSAR, Appendix 3D.1.30, Criterion 34 – Residual Heat Removal.

2. UFSAR, Section 9.3.5.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Canal Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies within 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 reactor vessel, 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 within 10 CFR 100 limits, as provided by the guidance of Reference 3.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the water level in the refueling canal is an initial condition design parameter in the analysis of the fuel handling accident in containment postulated by 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. 3). Refueling canal water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum refueling canal water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits as provided by 10 CFR 100.
APPLICABILITY	LCO 3.9.6 is applicable when moving irradiated fuel assemblies within the containment. 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 3.7.14, "Spent Fuel Pool Water Level."

BASES

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated 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 of a component to a safe position.

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, March 23, 1972.

2. UFSAR, Section 15.4.7.

3. 10 CFR 100.10.