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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that reactor core SLs ensure specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and abnormalities. 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.

Although DNB is not an observable parameter during reactor operation, the observable parameters of neutron power, reactor coolant flow, temperature and pressure can be related to DNB through the use of a critical heat flux (CHF) correlation. The BAW-2 (Ref. 2), BWC (Ref. 3), and BHTP (Ref. 9) correlations have been developed to predict DNB and the location of DNB for axially uniform and non-uniform heat flux distributions. The BAW-2 correlation applies to Mark-B fuel, the BWC correlation applies to Mark-BZ fuel, and the BHTP correlation applies to Mark-BHTP fuel. The local DNB ratio (DNBR), defined as the ratio of the heat flux that would cause DNB at a particular core location to the actual heat flux, is indicative of the margin to DNB. The minimum value of the DNBR, during steady state operation, normal operational transients and anticipated transients is limited to 1.30 (BAW-2), 1.18 (BWC), and 1.132 (BHTP).

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 CHF correlation for the core design. In the development of the applicable DNBR design limit, uncertainties in the core state variables, power peaking factors, manufacturing-related parameters, and the CHF correlation may be 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 (Ref. 4).

The restrictions of this SL 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. The maximum fuel centerline temperatures are given by the relationships defined in SL 2.1.1.1 for the respective fuel designs and are dependent on whether the TACO2 (Ref. 5) or TACO3 (Ref. 6) analysis was utilized. 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.

BACKGROUND (continued)

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. The oxidized cladding then exists in a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

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 abnormalities. 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 analyzed combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a DNBR of less than the DNBR limit and preclude the existence of flow instabilities (Ref. 7).

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

a. RCS High Pressure trip;

b. RCS Low Pressure trip;

c. Nuclear Overpower trip;

d. RCS Variable Low Pressure trip (also known as Pressure Temperature Trip);

e. Reactor Coolant Pump to Power trip;

f. Nuclear Overpower RCS Flow and AXIAL POWER IMBALANCE trip; and

g. RCS High Temperature trip.

APPLICABLE SAFETY ANALYSES (continued)

The SL represents a design requirement for establishing the RPS trip setpoints identified previously.

SAFETY LIMITS

SL 2.1.1.1, SL 2.1.1.2, and SL 2.1.1.3 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, the COLR identifies the pressure/temperature operating region that keeps the reactor from reaching an SL when operating up to design power.

The COLR presents the most limiting condition of pressure/temperature combinations for all possible reactor coolant pump maximum THERMAL POWER combinations. Analyses have been performed which bound the three pump and two pump (one pump in each loop) allowed operating conditions based on the expected minimum flow rates and maximum ALLOWABLE THERMAL POWER for these operating conditions.

The SLs are preserved by monitoring the process variable AXIAL POWER IMBALANCE to ensure that the core operates within the fuel design criteria. AXIAL POWER IMBALANCE protective limits are preserved by their corresponding RPS setpoints in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation," and are provided in the COLR. The trip setpoints are derived by adjusting the measurement system independent AXIAL POWER IMBALANCE protective limits given in the COLR to allow for measurement system observability and instrumentation errors.

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, SL 2.1.1.2, and SL 2.1.1.3 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. 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. Setpoints for the reactor trip 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 responses are applicable to the reactor core SLs.

2.2.1 AND 2.2.2

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, the requirement to go to MODE 3 places the plant in a MODE in which these SLs are not applicable.

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.

2.2.5

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 8).

REFERENCES

1. SAR, Section 1.4, GDC 10.

2. BAW-10000A, “Correlation of Critical Heat Flux in a Bundle Cooled by Pressurized Water,” Babcock & Wilcox, Lynchburg, VA, May 1976 .

3. BAW-10143P-A, “BWC Correlation of Critical Heat Flux,” Babcock & Wilcox, Lynchburg, VA, April 1985.

4. BAW-10179P-A, “Safety Criteria and Methodology for Acceptable Cycle Reload Analyses,” Rev. 6, Babcock & Wilcox, Lynchburg, VA, August 2005.

5. BAW-10141P-A, Rev. 1, “TACO2 Fuel Pin Performance Analysis,” Babcock & Wilcox, Lynchburg, VA, June 1983.

5. BAW-10162P-A, “TACO3 Fuel Pin Thermal Analysis Code,” Babcock & Wilcox, Lynchburg, VA, October 1989.

7. SAR, Chapters 3 & 14.

8. 10 CFR 50.72.

9. BAW-10241P-A, Rev. 1, “BHTP DNB Correlation Applied with LYNXT,” Framatome ANP, Lynchburg, VA, July 2005.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

In SAR, Section 1.4 (Ref. 1), GDC 14, “Reactor Coolant Pressure Boundary (RCPB),” and GDC 15, “Reactor Coolant System Design”, address RCPB design and protection, respectively. The ANO-1 discussion regarding how GDC 15 is accomplished states that analysis and evaluation of all normal and abnormal operating conditions and transients are integrally related to all RCS and associated systems design. SAR Chapter 14 (Ref. 2) lists these abnormal operating conditions and transients and terms them “abnormalities”. In addition, GDC 28, "Reactivity Limits" (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 abnormalities, the RCS pressure is kept from exceeding the design pressure by more than 10% in order to remain in accordance with the design codes (Ref. 3 and 4). Hence, the safety limit is 2750 psig. To ensure system integrity, all RCS components were hydrostatically tested at 125% of design pressure prior to initial operation, according to the design code requirements. Inservice leak testing at not less than 2155 psig is also required, prior to MODE 2, following any opening of the reactor coolant system in accordance with ASME code, Section XI; IWA-5000. When performed at the end of refueling outages, this leak test also satisfies the requirements of IWB-2500, Table IWB-2500-1; Category B-P items B15.10, B15.20, B15.30, B15.40, B15.50, B15.60, and B15.70 for all Class I pressure retaining components (Ref. 5).

APPLICABLE SAFETY ANALYSIS

The RCS pressurizer 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 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. 3). The design basis transient that is most influential for establishing the required relief capacity, and hence the valve size requirements and lift settings, is a rod withdrawal event from low power.

The startup event analysis (rod withdrawal at low power) (Ref. 2) is performed using conservative assumptions relative to pressure control devices.

APPLICABLE SAFETY ANALYSIS (continued)

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

a. Electromatic relief valve (ERV);

b. Steam line turbine bypass valves;

c. Control system runback of reactor and turbine power; and

d. Pressurizer spray valve

SAFETY LIMITS

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 USAS B31.7 (Ref. 4), 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. 6).

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 significantly.

SAFETY LIMIT VIOLATIONS

The following SL violation responses 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.

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. 6).

SAFETY LIMIT VIOLATIONS (continued)

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

2.2.4

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

Exceeding 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.

2.2.5

If the RCS pressure SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 7).

REFERENCES

1. SAR, Section 1.4, GDC 14, GDC 15, and GDC 28, 1988.
2. SAR, Chapter 14.
3. ASME Boiler and Pressure Vessel Code, Section III, 1965-S67, Article NB-7000.
4. USAS B31.7, Nuclear Power Piping, 1969.
5. ASME Boiler and Pressure Vessel Code, Section XI, Article IW-5000.
6. 10 CFR 100.
7. 10 CFR 50.72.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs

LCO 3.0.1 through LCO 3.0.7 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 complicance 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 Specification.

BASES

LCO APPLICABILITY (continued)

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 APPLICABILITY (continued)

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.

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 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.

BASES

LCO APPLICABILITY (continued)

LCO 3.0.3 (continued)

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 3.7.12, "Fuel Handling Area Ventilation System." LCO 3.7.12 has an Applicability of "During movement of irradiated fuel assemblies in the fuel handling area." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.12 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 3.7.12 of "Suspend movement of irradiated fuel assemblies in the fuel handling area" 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 precludes placing the unit in a MODE or other specified condition stated in that Applicability (e.g., Applicability desired to be entered) when the following exist:

a. Unit conditions are such that the requirements of the LCO would not be met in the Applicability desired to be entered; and

b. Continued noncompliance with the LCO requirements, if the Applicability were entered, would result in the unit being required to exit the Applicability desired to be entered to comply with the Required Actions.

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. 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.

BASES

LCO APPLICABILITY (continued)

LCO 3.0.4 (continued)

The provisions of LCO 3.0.4 shall not prevent changes in 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 changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

Exceptions to LCO 3.0.4 are stated in the individual Specifications. The exceptions allow 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. Exceptions may apply to all the ACTIONS or to a specific Required Action of a Specification.

LCO 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, LCO 3.0.4 is applicable when entering any other specified condition in the Applicability associated with operation in MODES 1, 2, 3, or 4. The requirements of LCO 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

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, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4 or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated 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:

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

BASES

LCO APPLICABILITY (continued)

LCO 3.0.5 (continued) 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.

LCO 3.0.6 LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an 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 system's 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' LCOs' 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.

BASES

LCO APPLICABILITY (continued)

LCO 3.0.6 (continued) 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 in 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 5.5.15, "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.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the remaining OPERABLE support systems are OPERABLE, thereby ensuring safety function is retained. 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 operation is 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).

When a 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

BASES

LCO APPLICABILITY (continued)

LCO 3.0.6 (continued) 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.

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.

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 Special Test Exception (STE) LCO are only applicable when the STE LCO is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

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.

BASES

SR APPLICABILITY (continued)

SR 3.0.1 (continued)

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. Emergency feedwater (EFW) pump turbine maintenance during refueling that requires testing at steam pressures > 800 psi. However, if other appropriate testing is satisfactorily completed, the EFW 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 EFW pump testing.

b. High pressure injection (HPI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

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 unit operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

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.

BASES

SR APPLICABILITY (continued)

SR 3.0.2 (continued)

These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is the Reactor Building Leakage Rate Testing Program.

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.

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, operational 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 the full delay period of up to the specified

BASES

SR APPLICABILITY (continued)

SR 3.0.3 (continued)

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, NRC 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 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.

BASES

SR APPLICABILITY (continued)

SR 3.0.3 (continued) Satisfactory 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.

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 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.

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 changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

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 Applicability would have its Frequency

BASES

SR APPLICABILITY (continued)

SR 3.0.4 (continued) 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.

SR 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability associated with operation in MODES 1, 2, 3 or 4. The requirements of SR 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

The reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions per GDC 26 (Ref. 1). In MODES 3, 4, and 5, SDM requirements provide sufficient reactivity margin to maintain the core subcritical during these conditions.

In MODES 1 and 2 while critical, SDM requirements are met by the worth of the withdrawn CONTROL RODS which provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and abnormalities. In MODE 2 while subcritical and in MODE 3, with all safety rods withdrawn and the RPS not in Shutdown Bypass, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion of all CONTROL RODS , assuming the single CONTROL ROD of highest reactivity worth is fully withdrawn. In MODES 3, 4, or 5, when all safety rods are not fully withdrawn or the RPS is in Shutdown Bypass, the SDM defines the degree of subcriticality required to be maintained, assuming the CONTROL ROD 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 CONTROL RODS and soluble boric acid in the Reactor Coolant System (RCS). In MODES 1 and 2, 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, for analyzed events initiated in MODES 1 and 2, the CONTROL RODS, together with the Chemical Addition and Makeup and Purification System, provide SDM during power operation and 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 (Ref. 1).

The Chemical Addition 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 (Ref. 1).

During operation in 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 LCO 3.2.1, "Regulating Rod Insertion Limits." In MODE 3, consideration must be given to the position of the safety rods and whether the RPS is in Shutdown Bypass in determining the required SDM. When the unit is

BACKGROUND (continued)

in MODES 3, 4, and 5, the SDM requirements are met by means of adjustments to the RCS boron concentration. Shutdown boron concentration requirements assume the highest worth rod is stuck in the fully withdrawn position to account for a postulated inoperable CONTROL ROD prior to reactor shutdown.

APPLICABLE SAFETY ANALYSES

For analyzed events in MODES 1 and 2 while critical, the minimum required SDM is assumed as an initial condition in safety analysis. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and abnormalities, with assumption of the highest worth rod stuck out following a reactor trip.

In MODES 1 and 2 while critical, 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; and

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 abnormalities, and $\leq$ 280 cal/gm energy deposition for the rod ejection accident).

In MODES 3, 4, and 5, the SDM requirements must ensure that the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

In MODES 1 and 2 while critical, SDM satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3). In MODE 2 while subcritical and in MODES 3, 4, and 5, SDM satisfies Criterion 4 of 10 CFR 50.36.

LCO

In MODES 1 and 2, and in MODE 3 when all safety rods are fully withdrawn and the RPS is not in Shutdown Bypass, SDM is a core design condition that can be ensured through CONTROL ROD positioning (regulating and safety groups) and through the soluble boron concentration.

In MODE 3, when all safety rods are not fully withdrawn or the RPS is in Shutdown Bypass, and in MODES 4 and 5, SDM represents a required degree of subcriticality that assumes the highest reactivity worth CONTROL ROD is fully withdrawn.

APPLICABILITY

In MODES 3, 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to ensure that the reactor remains subcritical.

In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5 and LCO 3.2.1. In MODE 6, the 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.

In the determination of the required combination of boration flow rate and boron source 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 tank (BAAT) or the borated water storage tank (BWST). The operator should borate with the best source available for the unit conditions.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

The SDM is verified by performing a reactivity balance calculation. The reactivity effects that are considered in the reactivity balance are dependent upon the operational MODE of the unit. In general, the reactivity balance includes 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. Xenon concentration;

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.1.1 (continued)

f. Samarium concentration;

g. Isothermal temperature coefficient (ITC);

h. Moderator temperature coefficient (MTC); and

i. Doppler defect.

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

Using the MTC and Doppler defect accounts for the reactivity effects of power operation above the POAH.

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 may include performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. SAR, Section 1.4, GDC 26.

2. SAR, Chapter 3.

3. 10 CFR 50.36.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Balance

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and abnormalities. Therefore, the reactivity balance is used as a measure of the agreement between the predicted core reactivity and the actual core reactivity during power operation. The periodic confirmation of the predicted 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 the predicted core reactivity with the actual core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations in ensuring the reactor can be brought safely to cold, subcritical conditions. The difference between the actual and predicted core reactivity is commonly referred to as a reactivity anomaly.

When the reactor is critical in MODE 1 or 2, a reactivity balance exists where the net reactivity is zero (referred to as the actual core reactivity state). A comparison of predicted core reactivity and the actual core reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions and the net reactivity is known to be zero. 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 soluble boron and burnable absorbers, producing zero net reactivity.

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, the excess positive reactivity of the fuel is compensated by burnable absorbers, CONTROL RODS, APSRs, thermal feedback from the fuel and moderator, fission product poisons (mainly xenon and samarium), epithermal energy neutron absorbers, neutron leakage and the reactor coolant system (RCS) boron concentration. During cycle operation, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the primary method of compensating for the reduction in excess reactivity is through a reduction in the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are the establishment of the reactivity balance limit to ensure that unit 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 is, therefore, dependent upon an 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 (Ref. 2). These accident analysis evaluations rely on computer codes which have been qualified against available test data, operating unit data, and analytical benchmarks. Monitoring the core 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 requirements for reactivity control during the operating cycle.

The comparison between the actual reactivity condition of the critical reactor and the predicted initial core reactivity provides an opportunity for the normalization of the calculational models used to predict core reactivity. If the predicted core reactivity and the actual core reactivity at reference core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict reactivity requirements may not be accurate. If reasonable agreement between the actual and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the predicted reactivity condition from the actual reactivity condition during the operating cycle may be an indication that the calculational model is not adequate for the operating cycle or that an unexpected change in core conditions has occurred.

The normalization of the predicted reactivity parameters to the actual reactivity value is typically performed after reaching RTP following startup from a refueling outage, with the RCS temperature, CONTROL RODS, and APSRs in their reference positions and fission product poisons at their expected equilibrium concentrations. 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 (Ref. 3).

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 accident 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% Δk/k has been established, based on engineering judgment. A ± 1% Δk/k deviation in the predicted reactivity from the actual reactivity condition of the reactor is larger than expected for normal operation and should therefore be evaluated.

When the predicted core reactivity is within 1% Δk/k of the actual reactivity value at steady state thermal conditions, the core is considered to be operating within acceptable design limits.

APPLICABILITY

In MODES 1 and 2, the limits on the core reactivity balance must be maintained to ensure an acceptable SDM and continued adherence to the assumptions used in the accident analyses. 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 the net reactivity condition of the reactor can not be easily determined and changes to core reactivity due to fuel depletion cannot occur.

In MODE 6, boron concentration requirements (LCO 3.9.1, "Refueling Boron Concentration") ensure that fuel movements are performed within acceptable bounds.

ACTIONS

A.1 and A.2

Should an anomaly develop between the actual core reactivity and the predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with the input assumptions used in the core 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 an abnormality or

ACTIONS (continued)

A.1 and A.2 (continued)

accident occurring during this period, and allows sufficient time to assess the physical condition of the core 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 reference conditions at the time of the reactivity balance, then a recalculation of the reactivity balance 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 appropriate reactivity parameter may be renormalized, and operation in MODE 1 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.

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 the core reactivity balance cannot be restored to within the ±1% Δk/k limit, the unit must be brought to a MODE in which the LCO does not apply. As a conservative measure, 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 RTP in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by a periodic reactivity balance calculation that compares the predicted core reactivity to the actual core reactivity condition (net reactivity of zero condition). The comparison is made considering that core conditions are fixed or stable, including CONTROL ROD and APSR positions, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed once prior to entering MODE 1 after each fuel loading as an initial check on core reactivity conditions and design calculations at BOC. A Note is included in the SR to indicate that the normalization of predicted

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.2.1 (continued)

core reactivity to the measured value may take place within the first 60 effective full power days (EFPD) after each fuel loading. The required 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. The 60 EFPD after entering MODE 1 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. Another Note is included in the SRs to indicate that the performance of the Surveillance is not required for entry into MODE 2.

REFERENCES

1. SAR, Section 1.4, GDC 26, GDC 28, and GDC 29.

2. SAR, Chapter 3A and 14.

3. 10 CFR 50.36

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and associated Reactor Coolant System (RCS) shall be designed so that in the power operating range the net affect of the prompt inherent nuclear feedback characteristic tends to compensate for a rapid increase in reactivity.

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). Therefore, with a negative MTC a coolant temperature increase will cause a reactivity decrease. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

Both initial and reload cores are designed so that the beginning of cycle (BOC) MTC is less than or equal to 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 are evaluated to ensure the MTC does not become more negative than the value assumed in the safety analyses.

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 for overheating events, to ensure the accident results are bounding.

The acceptance criteria for the specified MTC are:

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

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

APPLICABLE SAFETY ANALYSES (continued)

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 is the startup accident.

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 steam line break (SLB) event. Following the reactor trip for the postulated EOC SLB 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 may be 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.

In MODES 1 and 2 while critical, MTC satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3). In MODE 2 while subcritical, MTC satisfies Criterion 4 of 10 CFR 50.36.

LCO

LCO 3.1.3 requires the MTC to be within specified limits 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 original accident analysis during operation. The LCO establishes a maximum positive value that can not be exceeded. The limit of +0.9E-4 $\Delta k/k/°F$ (corrected to 95% RTP) 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 non-positive MTC, when THERMAL POWER is ≥ 95% RTP, ensures that core operation will be stable.

MTC is a core physics parameter determined by the fuel and fuel cycle design and cannot be controlled directly once the core design is fixed during operation, therefore, the LCO can only be ensured through measurement. The surveillance check at BOC on MTC provides 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 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 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 core physics parameter determined by 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 assumptions. 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 RTP in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The SR for measurement of the MTC at the beginning of each fuel cycle provides 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.

The requirement for measurement, prior to initial operation in MODE 1, satisfies the confirmatory check on the most positive (least negative) MTC value. MTC values are extrapolated and compensated to permit direct comparison to the specified MTC limits.

REFERENCES

1. SAR, Section 1.4, GDC 11.

2. SAR, Chapter 3A and 14.

3. 10 CFR 50.36.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 CONTROL ROD Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY of the CONTROL 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 SDM.

The applicable criteria for these design requirements are GDC 10, "Reactor Design," and GDC 26, "Reactivity Control System Redundancy-and Capability" (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 CONTROL 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 CONTROL 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 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 CONTROL RODS provide required negative reactivity worth for immediate reactor shutdown upon a reactor trip. The regulating rods provide reactivity control during normal operation and transients, and their movement is normally controlled in automatic by a rod control system.

The axial position of the CONTROL RODS is indicated by three independent systems, which are the relative position indicators, the absolute position indicators, and the zone reference indicators (see LCO 3.1.7, "Position Indicator Channels").

BACKGROUND (continued)

The relative position indicator transducer is a potentiometer that is driven by electrical pulses from the CRDCS. There is one counter for each CONTROL ROD drive. Individual rods in a group, when aligned to the same power supply, all receive the same signal to move; therefore, the counters for all rods in a group should normally indicate the same position. The Relative Position Indicator System is considered highly precise. However, if a rod does not move for each demand pulse, the counter will still count the pulse 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 the relative position indicators. This system is based on the signals from a series of reed switches spaced along a tube.

Other reed switches included in the same tube with the absolute position indicator matrix provide full in and full out limit indications and position indications at 0%, 25%, 50%, 75%, and 100% travel. This series of seven indicators are called zone reference indicators.

APPLICABLE SAFETY ANALYSES

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

a. There shall be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core must remain subcritical after an abnormality or accident.

Two types of misalignment are distinguished during MODES 1 and 2. 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 CONTROL 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 accident analysis and reload safety evaluations define regulating rod insertion limits that ensure the required SDM can always be achieved if the maximum worth CONTROL ROD is stuck fully withdrawn (Ref. 3). If a CONTROL ROD is stuck in or dropped in, continued operation is permitted if the increase in local LHR is within

APPLICABLE SAFETY ANALYSES (continued)

the design limits. The Required Action statements in the LCOs provide conservative reductions in THERMAL POWER and verification of SDM to ensure continued operation remains within the bounds of the safety analysis (Ref. 3).

Continued operation of the reactor with a misaligned or dropped CONTROL ROD is allowed if the local core LHRs are verified to be within their limits in the COLR. When a CONTROL ROD is misaligned, the assumptions that are used to determine the regulating rod insertion limits, APSR insertion limits, AXIAL POWER IMBALANCE limits, and QPT limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and local core LHRs must be verified directly by incore mapping. Bases Section 3.2, “Power Distribution Limits,” contains a more complete discussion of the relation of LHR to the operating limits.

In MODES 1 and 2 while critical, the CONTROL ROD group alignment limits satisfy Criterion 2 of 10 CFR 50.36 (Ref. 4). In MODE 2 while subcritical, the CONTROL ROD group alignment limits satisfy Criterion 4 of 10 CFR 50.36.

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 limit for individual CONTROL ROD misalignment is 6.5% (approximately 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, group average position calculator, and asymmetric alarm or fault detector outputs. Therefore, no additional uncertainties are required to be incorporated in the implementing procedures.

For the purpose of complying with this LCO, the position of a misaligned rod is not included in the calculation of the rod group average position. A CONTROL ROD is not considered to be inoperable due solely to misalignment. A CONTROL ROD is considered to be inoperable if it is not free to insert into the core within the required insertion time, or as directed by LCO 3.1.7, "Position Indicator Channels."

Failure to meet the requirements of this LCO may produce unacceptable 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 significant neutron (or fission) power is generated, and the OPERABILITY 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 reactor is shut down and resultant local power peaking would not exceed fuel design limits. In MODES 3, 4, 5, and 6, the OPERABILITY of the CONTROL 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 LCO 3.9.1, "Boron Concentration," for boron concentration requirements during MODE 6.

ACTIONS

A.1.1

Compliance with Required Actions of Condition A allows for continued power operation with one CONTROL ROD inoperable, or misaligned from its group average position, or both. 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 established in the COLR within 1 hour is adequate to determine that further degradation of the SDM is not occurring.

A.1.2

If the SDM is less than the limit specified in the COLR, then the 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.2.1

Alignment of the inoperable or misaligned 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 inoperable or 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," given in the COLR. THERMAL POWER must

ACTIONS (continued)

A.2.1 (continued)

also be restricted, as necessary, to the value allowed by the insertion limits of LCO 3.2.1. The required Completion Time of 2 hours is acceptable because local xenon redistribution during this short interval will not cause a significant increase in LHR. This option of inserting the group to the position of the misaligned rod is not available if a safety rod is misaligned, since the limits of LCO 3.1.5, "Safety Rod Insertion Limits," would be violated. If realignment of the CONTROL ROD to the group average or alignment of the group to the misaligned CONTROL ROD is not completed within 1 hour, the rod shall be considered inoperable.

A.2.2.1

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.

A.2.2.2

The existing CONTROL ROD configuration must not cause an ejected rod to exceed the limit of 0.65% Δk/k at RTP or 1.00% Δk/k at zero power (Ref. 3). 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 duration of time that operation is expected to continue with a misaligned rod. Should fuel cycle conditions at some later time become more bounding than those at the time of the rod misalignment, additional evaluation will be required to verify the continued acceptability of operation. 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.2.2.3

Performance of SR 3.2.5.1 provides a determination of the local core LHRs using the Incore Detector System. Verification of the local core LHRs 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 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.

ACTIONS (continued)

A.2.2.3 (continued)

Required Action A.2.2.3 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.”

B.1

If the Required Actions and associated Completion Times for Condition A are 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. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from RTP in an orderly manner and without challenging unit systems.

C.1.1

More than one CONTROL ROD becoming inoperable or misaligned from their group average position, or both, 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

If the SDM is less than the limit specified in the COLR, then the restoration of the required SDM requires increasing the RCS boron concentration to provide negative reactivity. RCS boration must occur as described in Bases Section 3.1.1. 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.

C.2

If more than one CONTROL ROD is inoperable or misaligned from their group average position, 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 inoperable at a given THERMAL POWER level, or if one or more CONTROL RODS become misaligned by insertion from the group average position.

ACTIONS (continued)

C.2 (continued)

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. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from RTP in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual CONTROL 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 CONTROL ROD position information that is continuously available to the operator in the control room, so that during actual CONTROL 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 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 approximately 1.5% (approximately 2 inches) will not cause radial or axial power tilts, or oscillations, to occur. No additional allowances for instrument uncertainty are required to be incorporated in the implementing procedures for this parameter. 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 typical 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 otherwise determined to be capable of being fully inserted, the CONTROL ROD(S) may continue to be considered OPERABLE unless inoperable for some other reason. At any time, if a CONTROL ROD(S) is immovable, a determination of the capability to fully insert (OPERABILITY) the CONTROL ROD(S) must be made, and appropriate action taken.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verification of CONTROL ROD drop time allows the operator to determine that the maximum CONTROL ROD drop time permitted is consistent with the assumed CONTROL ROD drop time used in the safety analysis. The CONTROL ROD drop time given in the safety analysis is 1.66 seconds to 3/4 position insertion (Ref. 5). This 1.66 seconds includes 0.21 seconds delay time for opening of the CRD breakers and for CRDM unlatch. Using the CONTROL ROD position versus time and time versus reactivity insertion curves gives a value of 1.4 seconds to 2/3 reactivity insertion upon which the accident analysis is based (Ref. 3). The former value is used in the Surveillance because the zone reference lights are located at 25% insertion intervals. The zone reference lights will activate at 3/4 insertion to give an indication of the CONTROL ROD drop time and CONTROL ROD location. The CONTROL ROD drop time is the total elapsed time from the loss of power to the control rod drive (CRD) breaker under voltage coils until the CONTROL ROD has completed approximately 104 inches of travel from the fully withdrawn position. The safety analysis has included a CRD breaker time delay of 0.080 seconds in SAR Chapter 14 (Ref. 3). If the trip test measurement is begun with the opening of the CRD breakers, the required trip insertion time shall be reduced to 1.58 seconds and the CRD breaker time delay shall be verified to be less than or equal to 0.080 seconds.

Measuring CONTROL 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 CONTROL ROD drop time. This Surveillance is performed during a unit outage, due to the unit conditions needed to perform the SR and the potential for an unplanned unit transient if the Surveillance were performed with the reactor at power.

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 CONTROL ROD drop times are determined with less than four reactor coolant pumps operating, a Note allows operation to continue, provided operation is restricted to the pump combination utilized during the CONTROL ROD drop time determination or pump combinations providing less total reactor coolant flow.

REFERENCES

1. SAR, Section 1.4, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. SAR, Chapter 3A and 14.
4. 10 CFR 50.36.
5. SAR, Chapter 3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Safety Rod Insertion Limits

BASES

BACKGROUND

The insertion limits of the CONTROL RODS are initial condition assumptions in all safety analyses that assume CONTROL 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 GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability," GDC 28, "Reactivity Limits" (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 CONTROL ROD positions are monitored and controlled during operation in MODES 1 and 2 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 automatic control system, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). In MODES 1 and 2, the regulating groups must be maintained above designated 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. Prior to entry into MODE 2 from MODE 3, the safety groups must be 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. They add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all CONTROL RODS, 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 group insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from RTP. 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 achieve the required SDM at rated no load temperature (Ref. 3).

The acceptance criteria for addressing safety and regulating rod group insertion limits and inoperability or misalignment are that:

a. There shall be no violations of:

   1. specified acceptable fuel design limits, or
   2. RCS pressure boundary integrity; and

b. The core must remain subcritical after an abnormality. Although the SAR does not state this as an acceptance criteria for the main steam line break event, B & W has placed a design objective on this event that the core remains subcritical throughout the event (Ref. 4).

In MODES 1 and 2 while critical, the safety rod insertion limits satisfy Criteria 2 and 3 of 10 CFR 50.36 (Ref. 5). In MODE 2 while subcritical, the safety rod insertion limits satisfy Criterion 4 of 10 CFR 50.36.

LCO

The safety groups must be fully withdrawn any time the reactor is in MODE 1 or 2. This LCO in combination with LCO 3.2.1 ensures that a sufficient amount of negative reactivity is available to shut down the reactor and achieve 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 LCO in combination with LCO 3.2.1 ensures that a sufficient amount of negative reactivity is available to shut down the reactor and achieve 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 inoperable within a 1 hour time frame. This requires entry into 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.

Restoration of the required SDM, if necessary, requires increasing the boron concentration, since the safety rod may remain misaligned and not be providing its normal negative reactivity on tripping. 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 unit 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 any rod not capable of being fully inserted as well as the CONTROL ROD of maximum worth.

ACTIONS (continued)

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 RTP in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that each safety rod is fully withdrawn ensures the safety 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 safety 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. SAR, Section 1.4, GDC 10, GDC 26, and GDC 28.

2. 10 CFR 50.46.

3. SAR, Chapters 3 and 4.

4. BAW-10179P-A, “Safety Criteria and Methodology for Acceptable Cycle Reload Analyses,” Rev. 2.

5. 10 CFR 50.36.

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 APSR alignment are initial condition assumptions in the safety analysis that directly affect core power distributions. The applicable criteria for these power distribution design requirements are GDC 10, "Reactor Design," and GDC 28, "Reactivity Limits" (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 APSR and CONTROL ROD positions are monitored and controlled during power operation to ensure that the power distribution limits defined by the design peaking limits are preserved.

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

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

LCO 3.1.6 is conservatively based on use of black (Ag-In-Cd) APSRs and bounds use of gray (Inconel) APSRs. The reactivity worth of black APSRs is greater than that of gray APSRs; thus the impact of black APSR misalignment on the core power distribution is greater.

APPLICABLE SAFETY ANALYSES

There are no explicit safety analyses associated with misaligned APSRs. However, alignment of the APSRs is required to prevent inducing a QUADRANT POWER TILT. The LCOs governing APSR alignment are provided because the power distribution analysis supporting LCO 3.2.1, LCO 3.2.3 and LCO 3.2.4 assumes the APSRs are aligned.

During movement of an APSR group, one rod may stop moving while the other rods in the group continue. This condition may cause excessive power peaking. Continued operation of the reactor with a misaligned APSR is allowed if Section 3.2, “Power Distribution Limits,” are preserved.

Because ANO-1 uses gray APSRs, the APSR alignment limits satisfy Criterion 4 of 10 CFR 50.36 (Ref. 3).

LCO

The limits on CONTROL ROD group alignment, safety rod withdrawal, 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% (approximately 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, group average position calculator, and asymmetric alarm or fault detector outputs. Therefore, no additional uncertainties are required to be incorporated in the implementing procedures. The position of an inoperable APSR is not included in the calculation of the APSR group's average position.

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

APPLICABILITY

The requirements on APSR OPERABILITY and alignment are applicable in MODES 1 and 2, because these are the only MODES in which significant neutron (or fission) power is generated, and the OPERABILITY and alignment of APSRs have the potential to affect the safety of the unit. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the reactor is shut down, and excessive local LHRs cannot occur from APSR misalignment.

ACTIONS

A.1

The ACTIONS described below are required if one APSR is inoperable. The unit is not allowed to operate with more than one inoperable APSR. This would require the reactor to be placed in MODE 3, 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 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 power peaking are surveilled within 2 hours to determine if power peaking is still within limits. Also, since any additional movement of the APSRs may result in additional imbalance, Required Action A.1 also requires the power peaking surveillance to be performed again within 2 hours after each APSR movement.

B.1

The unit 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 unit 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 unit systems. In MODE 3, APSR group alignment limits are not required because the reactor is not generating significant 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 APSR motion, deviations can immediately be detected.

REFERENCES

1. SAR, Section 1.4, GDC 10 and GDC 28.

2. 10 CFR 50.46.

3. 10 CFR 50.36.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Position Indicator Channels

BASES

BACKGROUND

According to the SAR discussion of GDC 13 (Ref. 1), adequate instrumentation and controls are provided to maintain operating variables within prescribed ranges for normal operation and monitor accident conditions as appropriate to assure adequate safety. 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 CONTROL RODS is an initial condition assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment for the CONTROL RODS and APSRs is assumed in the safety analysis, which directly affect 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 local linear heat rates (LHRs), due to the asymmetric reactivity distribution, and a reduction in the total available CONTROL ROD worth for reactor shutdown. Therefore, CONTROL ROD and APSR alignment are related to core operation within design LHR limits and the core design requirement of a minimum SDM. CONTROL ROD and APSR position indication is needed to assess OPERABILITY and alignment.

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

Three methods of CONTROL ROD and APSR position indication are provided in the Control Rod Drive Control System. The three means are by absolute position indicator, relative position indicator transducers, and zone reference indicators. The absolute position indicator transducer consists of 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 or APSR assembly leadscrew extension comes near. As the leadscrew and CONTROL ROD or APSR move, the switches operate sequentially, producing an analog voltage proportional to position. Other reed switches included in the same tube with the absolute position indicator matrix provide full in and full out limit indications, and position indications at 0%, 25%, 50%, 75%, and 100% travel. This series of seven

BACKGROUND (continued)

indicators are called zone reference indicators. The relative position indicator transducer is a potentiometer, driven by a step motor that produces a signal proportional to CONTROL ROD or APSR position, based on the electrical pulse steps that drive the CRDM.

CONTROL ROD and APSR position indicating readout devices located in the control room consist of single rod position meters on a position indication panel and group average position meters. A selector switch permits either relative or absolute position indication to be displayed on all of the individual position indication meters. Indicator lights are provided on the individual position indication panel to indicate when each CONTROL ROD or APSR is fully withdrawn, fully inserted, enabled, or transferred, and whether a rod position asymmetry alarm condition is present. Additional indicators show full insertion, full withdrawal, and enabled for motion for each CONTROL ROD and APSR group. The consequence of continued operation with an inoperable absolute position indicator or relative position indicator channel is a decreased reliability in determining CONTROL ROD and APSR position. Therefore, the potential for operation in violation of design LHR or SDM limits is increased.

APPLICABLE SAFETY ANALYSES

CONTROL ROD and APSR position accuracy is essential during power operation. LHR, 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. CONTROL ROD and APSR positions must be known in order to verify the core is operating within the group sequence, overlap, design LHRs, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Safety Rod Insertion Limits"; LCO 3.2.1, "Regulating Rod Insertion Limits"; and LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits"). The CONTROL ROD and APSR 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 unit is operating within the bounds of the accident analysis assumptions.

In MODES 1 and 2 while critical, the CONTROL ROD and APSR position indicator channels satisfy Criterion 2 of 10 CFR 50.36 (Ref. 3). In MODE 2 while subcritical, the CONTROL ROD and APSR position indicator channels satisfy Criterion 4 of 10 CFR 50.36.

LCO

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

This requirement ensures that CONTROL ROD and APSR position indication during MODES 1 and 2 and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channel ensures that inoperable, misaligned, or mispositioned CONTROL RODS or APSRs can be detected. Therefore, LHR and SDM can be controlled within acceptable limits.

APPLICABILITY

In MODES 1 and 2, OPERABILITY of the position indicator channel 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 significant THERMAL POWER.

ACTIONS

A.1

If the required position indicator channel is inoperable for one or more rods, the position of the CONTROL ROD or APSR is not known with certainty. Therefore, each affected CONTROL ROD or APSR 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

A CHANNEL CHECK of the required position indication channel ensures that position indication for each CONTROL ROD and APSR remains OPERABLE and accurate. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. However, this CHANNEL CHECK will be used to detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.1 (continued)

When compared to other channels, the agreement criteria between channels is determined by the unit staff. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

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 position indicator channel.

The required Frequency of 12 hours is adequate for verifying that no degradation in system OPERABILITY has occurred.

SR 3.1.7.2

A CHANNEL CALIBRATION of the required position indication channel verifies that the channel responds within the necessary range and accuracy.

The Frequency of 18 months is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. SAR, Section 1.4, GDC 13.

2. SAR, Chapter 14.

3. 10 CFR 50.36.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions Systems - MODE 1

BASES

BACKGROUND

The purpose of this 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 unit. All functions necessary to ensure that specified design conditions are not violated during normal operation and abnormalities 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:

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. 3).

The inclusion of this PHYSICS TESTS Exception LCO is acceptable based on the use of approved written procedures, administrative controls, the requirements of 10 CFR 50.59, and the LCO 3.1.8 provisions in effect during the conduct of PHYSICS TESTS. 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.

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 linear heat rate (LHR), ejected rod worth, and shutdown capability are maintained during the PHYSICS TESTS.

Reference 4 describes the initial testing of the facility, including PHYSICS TESTS. Table 13-2 (Ref. 5) summarizes the post-criticality tests. Requirements for reload fuel cycle PHYSICS TESTS are given in SAR Section 3A.9 (Ref. 3). 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";
LCO 3.2.2, “AXIAL POWER SHAPING ROD (APSR) Insertion Limits,” for the restricted operation region only;
LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits"; and
LCO 3.2.4, "QUADRANT POWER TILT (QPT)"

are suspended for PHYSICS TESTS, the fuel design criteria are preserved by maintaining the LHR (in MODE 1 PHYSICS TESTS) within 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 limit provided in the COLR. Therefore, surveillance of the LHR and SDM is required to verify that their limits are not exceeded. The limits for the LHR are specified in the COLR. Refer to the Bases for LCO 3.2.5 for a complete discussion of LHR. During PHYSICS TESTS, one or more of the LCOs that normally preserve the LHR limits may be suspended. However, the results of the safety analysis are not adversely impacted if verification that core LHRs are within their limits is obtained, while one or more of the LCOs is suspended. Therefore, SRs are placed on LHR during MODE 1 PHYSICS TESTS when THERMAL POWER exceeds 20% RTP to verify that the core LHRs 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 limits for these variables are specified for each fuel cycle in the COLR.

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36 (Ref. 6) apply. Test Exception LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion for the other LCOs is provided in their respective Bases.

LCO

This LCO permits individual CONTROL RODS and APSRs 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. Nuclear overpower trip setpoint is ≤ 10% RTP higher than the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP;

c. LHR is maintained within limits specified in the COLR while operating at greater than 20% RTP; and

d. SDM is verified to be within the limit provided in the COLR.

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 3. The nuclear overpower 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 LHR 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.”

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 described in SAR Section 3A.9 (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 initiated 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. The operator should begin boration with the best source available for the unit conditions. 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.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification. A Completion Time of one hour is provided for the operator to restore compliance with the excepted LCOs.

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 nuclear overpower trip setpoint is not within the specified limits, then 1 hour is allowed for the operator to restore the nuclear overpower 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.

ACTIONS (continued)

B.1 (continued)

If the results of the incore flux map indicate that LHR has exceeded its limit, then PHYSICS TESTS are suspended. This action is required because of direct indication that the core LHR, which is a fundamental initial condition for the safety analysis, is 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.”

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.

SR 3.1.8.2

Verification that core LHRs are within their limits ensures that core LHR 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 LHR verification, 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 LHR 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.”

SR 3.1.8.3

Verification that the nuclear overpower trip setpoint is within the limit specified for each PHYSICS TEST ensures that core protection at the reduced power level is established during the PHYSICS TESTS. Performing the verification once within 8 hours prior to the performance of PHYSICS TESTS at each testing plateau allows the operator adequate time for verifying the established trip setpoint before initiating PHYSICS TESTS.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering 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;

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. SAR, Section 3A.9.

4. SAR, Section 13.3, 13.4 and 13.6.

5. SAR, Section 13.4, Table 13-2.

6. 10 CFR 50.36.

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 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 unit. All functions necessary to ensure that specified design conditions are not violated during normal operation and abnormalities 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:

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. 3).

The inclusion of this PHYSICS TESTS Exception LCO is acceptable based on the use of approved written procedures, administrative controls, the requirements of 10 CFR 50.59, and the LCO 3.1.9 provisions in effect during the conduct of PHYSICS TESTS. 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.

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES

Reference 4 describes the initial testing of the facility, including PHYSICS TESTS. Table 13-2 (Ref. 5) summarizes the post-criticality tests. Requirements for reload fuel cycle PHYSICS TESTS are given in SAR Section 3A.9 (Ref. 3). 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";
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 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 unit 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 Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36 (Ref. 6) apply. Test Exception LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria for the other LCOs is provided in their respective Bases.

LCO

This LCO permits individual CONTROL RODS and APSRs 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, LCO 3.2.2, and LCO 3.4.2, provided:

a. THERMAL POWER is ≤ 5% RTP;

b. Nuclear overpower trip setpoints on the OPERABLE nuclear power range channels are set to ≤ 5% RTP;

c. Nuclear instrumentation high startup rate CONTROL ROD withdrawal inhibit is OPERABLE; and

d. SDM is within the limit provided in the COLR.

The limits of LCO 3.2.3 and LCO 3.2.4 are not exempted by this specification because they 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 described in SAR Section 3A.9 (Ref. 3). In MODE 1, Applicability of this LCO is not required because LCO 3.1.8, "PHYSICS TESTS Exceptions," addresses PHYSICS TESTS exceptions in MODE 1. In MODES 3, 4, 5, and 6, a test exception LCO is not required because the excepted LCOs do not apply 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 immediately tripped. The necessary prompt action requires manual operator action to 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. The operator should begin boration with the best source available for the unit conditions. 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.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification. A Completion Time of one hour is provided for the operator to restore compliance with the excepted LCOs.

C.1

If the nuclear overpower trip setpoint is > 5% RTP, then 1 hour is allowed for the operator to restore the nuclear overpower 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.

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 functions 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

Verification that THERMAL POWER is ≤ 5% RTP ensures that local LHR, DNBR, and RCS pressure limits are not violated and that entry into Actions Condition A is performed promptly. Hourly verification is adequate for the 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 3.1.9.2

Verification that the nuclear overpower trip setpoint is within the limit specified for PHYSICS TESTS ensures that core protection at the reduced power level is established during PHYSICS TESTS. Performing the verification once within 8 hours prior to the performance of PHYSICS TESTS allows the operator adequate time for verifying the established trip setpoint before initiating PHYSICS TESTS.

SR 3.1.9.3

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.

SURVEILLANCE REQUIREMENTS (continued)

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. SAR, Section 3A.9.
4. SAR, Section 13.3, 13.4 and 13.6.
5. SAR, Section 13.4, Table 13-2.
6. 10 CFR 50.36.

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 SDM, and the initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are described in SAR, Section 1.4, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability," GDC 28, "Reactivity Limits" (Ref. 1), and in 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

Limits on regulating rod insertion 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 not violated.

The regulating rod groups operate with a predetermined amount of position overlap, in order 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 rapid reactivity changes 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 monitored process variables to ensure that the core operates within the linear heat rate limits in the COLR. Operation within the linear heat rate limits given in the COLR prevents power peaks that would exceed the loss of coolant accident (LOCA) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS) and prevents departure from nucleate boiling (DNB) during a loss of forced

BACKGROUND (continued)

reactor coolant flow accident. In addition to the linear heat rate 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 support 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 or abnormalities. 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 large break 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. 4).

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

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, 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 linear heat rates (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.

APPLICABLE SAFETY ANALYSES (continued)

Operation at 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 and 4).

The regulating rod insertion limits LCO satisfies Criterion 2 of 10 CFR 50.36 (Ref. 5).

LCO

The limits on regulating rod group physical insertion, sequence, and overlap, 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 maximum allowable setpoints for regulating rod insertion are provided in the COLR. The setpoints 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, out of group sequence, or beyond group overlap requirements, which would otherwise violate the LCO.

APPLICABILITY

The regulating rod physical insertion, sequence, and overlap 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 rate insertion 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 setpoints provided in the COLR are based on the initial conditions assumed in the accident analyses and on the SDM. Specifically, separate insertion setpoints 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 setpoints are provided because different Required Actions and Completion Times apply, depending on which insertion setpoint has been violated. The area between the boundaries of the acceptable operation and unacceptable operation regions, illustrated on the regulating rod insertion setpoint figures in the COLR, is the restricted operation region. The actions required when operation occurs in the restricted operation region are described under Condition A. The actions required when operation occurs in the unacceptable operation region are described under Condition D. The actions required when operation occurs with the regulating rod group sequence or overlap requirements not met are described under Condition C.

A.1

Operation with the regulating rods in the restricted operation region shown on the regulating rod insertion setpoint figures specified in the COLR potentially violates the LOCA LHR limits, or the loss of flow accident DNB peaking limits.

For verification that LHRs 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 LHRs 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. 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 LHRs. Repeating SR 3.2.5.1 every 2 hours is acceptable because it ensures that continued verification of the LHRs is performed as core conditions (primarily regulating rod insertion and induced xenon redistribution) change.

Monitoring the LHRs 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 setpoint 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. 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.”

ACTIONS (continued)

A.2

Indefinite operation with the regulating rods inserted in the restricted operation 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 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 regulating rod groups to within their 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, thereby limiting the potential for an adverse xenon redistribution.

B.1

If the regulating rods cannot be positioned 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 setpoints can be restored by reducing the THERMAL POWER to a value allowed by the regulating rod insertion setpoints 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 unit 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 regulating rod position out of specification in this relatively short time period.

C.1

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. The design calculations assume no deviation in nominal overlap between regulating rod groups. However, small deviations in group overlap, as allowed by the COLR, may occur and would not cause significant differences in core reactivity, in power distribution, or rod worth, relative to the design calculations. Group sequence must be maintained because design calculations assume the regulating rods withdraw and insert in a predetermined order. The Completion Time of 4 hours is intended to restrict operation in this condition because of the potential severity associated with gross violations of group sequence or overlap requirements. 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.

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 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 operation region, which restores the minimum SDM 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 and purification systems, thereby allowing the regulating rods to be withdrawn to the restricted operation region. Operation in the restricted operation region for up to 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 setpoints 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 unit systems. Operation for up to 2 hours in the restricted operation region shown in the COLR is acceptable, 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 and limits the potential for an adverse xenon redistribution.

ACTIONS (continued)

E.1

If the Required Actions and associated Completion Times of Conditions C or D are 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 unit 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 during this period 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 setpoints as specified in the COLR at a Frequency of 12 hours is sufficient to detect regulating rod banks that may be approaching the group insertion setpoints, 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.

SR 3.2.1.3

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. SAR, Section 1.4, GDC 10, GDC 26 and GDC 28.
2. 10 CFR 50.46.
3. SAR, Chapter 3.
4. SAR, Chapter 14.
5. 10 CFR 50.36.

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 SAR Section 1.4, GDC 10, "Reactor Design" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

Limits on APSR insertion have been established, 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 linear heat rate (LHR) limits in the COLR. Operation within the LHR limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS) and prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident. The APSRs do not insert 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.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation or abnormalities. 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 large break LOCA, the peak cladding temperature must not exceed 2200°F (Ref. 2);

APPLICABLE SAFETY ANALYSES (continued)

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. CONTROL RODS must be capable of shutting down the reactor with a minimum required SDM which assumes the highest worth CONTROL ROD stuck fully withdrawn (GDC 26, Ref. 1).

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 linear heat rates.

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

In MODES 1 and 2 while critical, the APSR insertion limits satisfy Criterion 2 of 10 CFR 50.36 (Ref. 4). In MODE 2 while subcritical, the APSR insertion limits satisfy Criterion 4 of 10 CFR 50.36.

LCO

The setpoints 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 EFPD burnup window specified in the COLR. Prior to this window, the APSRs are maintained in accordance with operating guidelines provided by reactor engineering during steady state operation. After this window, the APSRs are not allowed to be reinserted for the remainder of the fuel cycle.

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. In MODES 1 and 2, the limits on APSR insertion specified by this LCO maintain the axial fuel burnup design conditions assumed in the reload safety evaluation analysis. Applicability in MODES 3, 4, and 5 is not required, because the reactor is subcritical.

ACTIONS

For steady state power operation, a normal position for APSR insertion is specified in the station operating procedures. 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 position 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 may not be maintained in the fully withdrawn position prior to the fuel cycle burnup for the APSR withdrawal. If this occurs, the APSRs must be restored to their normal inserted position. 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 linear heat rates 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 the LHRs are within their limits ensures that operation with the APSRs inserted or withdrawn in violation of the setpoints specified in the COLR do not violate either the ECCS or DNB criteria. The required Completion Time of 2 hours is reasonable to allow the operator to obtain a power distribution map and to verify the LHRs. Repeating SR 3.2.5.1 every 2 hours is reasonable to ensure that continued verification of the LHRs 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.”

A.2

Indefinite operation with the APSRs positioned in violation of the setpoints specified in the COLR is not prudent. Even if LHR monitoring per Required Action A.1 is continued, the abnormal APSR positioning 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, operation 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 position 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.

ACTIONS (continued)

A.2 (continued)

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 the Required Action and associated Completion Time are 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

Fuel cycle designs that allow APSR withdrawal near end of cycle (EOC) do not permit reinsertion of APSRs after the time of withdrawal. Verification that the APSRs are within their insertion setpoints at a 12 hour Frequency is sufficient to ensure that the APSR insertion setpoints 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.

REFERENCES

1. SAR, Section 1.4, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. SAR, Chapter 14.
4. 10 CFR 50.36.

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 linear heat rate (LHR) limits given in the COLR. Operation within the LHR limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS) and 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 LHR so that the peak cladding temperature does not exceed 2200°F (Ref. 1). 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.

The measurement system independent limits on AXIAL POWER IMBALANCE are determined analytically 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. The AXIAL POWER IMBALANCE setpoints provided in the COLR account for measurement system error and uncertainty.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and abnormalities. 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 large break 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.

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 the safety analyses. The axial power distribution is maintained primarily by the AXIAL POWER IMBALANCE and the APSR position 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 LHR assumed as initial conditions for the accident analyses with the allowed QPT present.

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

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 setpoints beyond which the core power distribution could 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 maximum allowable setpoints (measurement system dependent limits) applicable for the full Incore Detector System, the Minimum 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 based on engineering judgment 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.

ACTIONS

A.1

The AXIAL POWER IMBALANCE operating setpoints 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 setpoints given in the COLR is the acceptable region of operation. Operation in violation of the AXIAL POWER IMBALANCE setpoints 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 or the loss of flow accident DNB peaking limits or both. For verification that core local LHRs 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 core local LHRs are within their specified limits ensures that

ACTIONS (continued)

A.1 (continued)

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 core local LHRs are within their specified limits. The 2 hour Frequency provides reasonable time to ensure that continued verification of the core local LHRs 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 LHR monitoring per Required Action A.1 is continued, excessive AXIAL POWER IMBALANCE over an extended period of time may cause a potentially adverse xenon redistribution to occur. Therefore, LHR 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 setpoints 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 the Required Actions and the associated Completion Times of Condition A are 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 $\leq$ 40% RTP reduces the maximum LHR to a value that does not exceed the LHR initial condition limits assumed in the accident analyses. The required Completion Time of 4 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

SR 3.2.3.1

The AXIAL POWER IMBALANCE can be monitored by both the Incore and Excore Detector Systems. The AXIAL POWER IMBALANCE maximum allowable setpoints 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 full incore detector system limits assumes that 75% of the detectors in each quadrant are OPERABLE. Detectors located on the core major axes are assumed to contribute one half of their output to each quadrant; detectors in the center assembly are assumed to contribute one quarter of their output to each quadrant. For AXIAL POWER IMBALANCE measurements using the Incore Detector System, the Minimum Incore Detector System consists of OPERABLE detectors configured as follows:

a. Nine detectors shall be arranged such that there are three detectors in each of three strings and there are three detectors lying in the same axial plane, with one plane at the core midplane and one plane in each axial core half;

b. The axial planes in each core half shall be symmetrical about the core midplane; and

c. The detector strings shall not have radial symmetry.

Figure B 3.2.3-1 (Minimum Incore Detector System for AXIAL POWER IMBALANCE Measurement) depicts an example of this configuration. This arrangement is chosen to reduce the uncertainty in the measurement of the AXIAL POWER IMBALANCE by the Minimum Incore Detector System. For example, the requirement for placing one detector of each of the three strings at the core midplane puts three detectors in the central region of the core where the neutron flux tends to be higher. It also helps prevent measuring an AXIAL POWER IMBALANCE that is excessively large when the reactor is operating at low THERMAL POWER levels. The third requirement for placement of detectors (i.e., radial asymmetry) reduces uncertainty by measuring the neutron flux at core locations that are not radially symmetric.

Verification of the AXIAL POWER IMBALANCE indication every 12 hours ensures that the AXIAL POWER IMBALANCE setpoints are not violated and takes into account other information and alarms available 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.

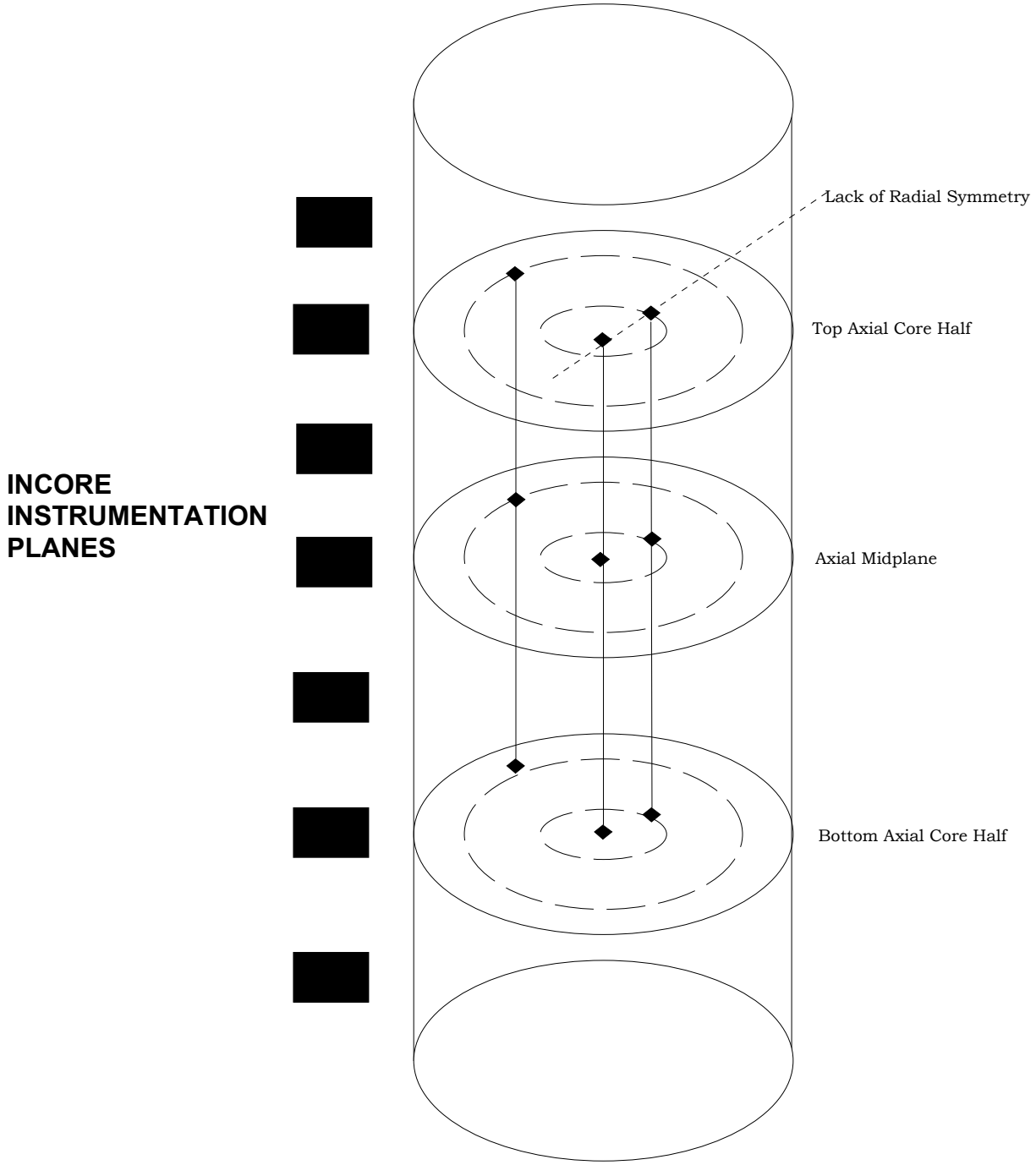
REFERENCES

1. 10 CFR 50.46.

2. 10 CFR 50.36.

Figure B 3.2.3-1

Minimum Incore System for AXIAL POWER IMBALANCE Measurement



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 linear heat rate (LHR) limits given in the COLR. Operation within the LHR limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) limits derived by Emergency Core Cooling Systems (ECCS) analysis and 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 LHR so that the peak cladding temperature does not exceed 2200°F (Ref. 1). 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 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.

BACKGROUND (continued)

The measurement system independent limits on QPT are determined analytically 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 setpoints (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 and abnormalities. 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 large break LOCA, the 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 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.

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.

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. 2). 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 LHR for accident initial conditions with the allowed QPT present.

QPT satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3).

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 setpoints and the AXIAL POWER IMBALANCE boundaries contained in the COLR represent the measurement system dependent limits at which the core power distribution could either exceed the LOCA LHR limits or cause 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 position determined by the fuel cycle design and specified by LCO 3.2.2.

The allowable setpoints for steady state and maximum setpoints for QPT applicable for the full symmetrical Incore Detector System, Minimum Incore Detector System, and Excore Detector System are provided in the COLR. The setpoints for the three systems are derived by adjustment of the measurement system independent QPT limits also given in the COLR 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.

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 greater than the maximum setpoint specified in the COLR in MODE 1 with THERMAL POWER < 20% RTP are allowed based on engineering judgement.

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

ACTIONS

A.1.1

The steady state setpoint 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 setpoint is allowed by the regulating rod insertion limits of LCO 3.2.1 and the AXIAL POWER IMBALANCE limits of LCO 3.2.3.

ACTIONS (continued)

A.1.1 (continued)

Operation with QPT greater than the steady state setpoint specified in the COLR potentially violates the LOCA LHR limits, or loss of flow accident DNB peaking limits, or both. For verification that core local LHRs 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 core local LHRs are within their limits ensures that operation with QPT greater than the steady state setpoint 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 core local LHRs. Repeating SR 3.2.5.1 every 2 hours is a reasonable Frequency at which to ensure that continued verification of the core local LHRs is obtained as core conditions that influence QPT change.

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 setpoint. This action limits the local LHR to a value corresponding to 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 setpoint 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 nuclear overpower based on Reactor Coolant System (RCS) flow and AXIAL POWER IMBALANCE trip setpoint, for each 1% of QPT in excess of the steady state limit. This reduction maintains both core protection and thermal margins at the reduced THERMAL POWER level similar to that at RTP. The required Completion Time of 10 hours or 10 hours after the last performance of SR 3.2.5.1 is reasonable based on the need to limit the potentially adverse xenon redistribution, the low probability of an accident occurring while operating with the QPT limits not met, and the number of steps required to complete the Required Action.

ACTIONS (continued)

A.1.2.3

Power operation is allowed to continue if restrictions are imposed on the allowed degree of regulating group insertion. This Required Action requires a reduction in the regulating group insertion setpoints given in the COLR by ≥ 2% RTP from the ALLOWABLE THERMAL POWER for each 1% of QPT greater than the steady state setpoint. Based on engineering judgment, this action is intended to reduce the potential power peaking associated with regulating rod group insertion into the core.

The 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 with QPT limits not met, and the number of steps required to complete the Required Action. The second Completion Time of 10 hours after the last performance of SR 3.2.5.1 is based on the same reasoning and is provided 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.1.2.4

Power operation is allowed to continue if restrictions are imposed on the allowed Operational Power Imbalance Setpoints given in the COLR. This Required Action results in a reduction in the allowed THERMAL POWER level as a function of AXIAL POWER IMBALANCE by ≥ 2% RTP from the ALLOWABLE THERMAL POWER for each 1% of QPT greater than the steady state limit. Based on engineering judgment, this action is intended to reduce the potential power peaking associated with the combined affects of operating with an AXIAL POWER IMBALANCE and a QPT.

The 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 with QPT limits not met, and the number of steps required to complete the Required Action. The second Completion Time of 10 hours after the last performance of SR 3.2.5.1 is based on the same reasoning and is provided 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.2

Although the actions directed by Required Action A.1.2.1 restore thermal 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 to reduce QPT to less than the steady state limit is a reasonable time for investigation and corrective measures.

ACTIONS (continued)

B.1

If the Required Actions and associated Completion Times of Condition A are not met, a further power reduction is required. Power reduction to < 60% of ALLOWABLE THERMAL POWER provides conservative protection from increased peaking due to xenon redistribution. 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 unit systems.

B.2

Reduction of the nuclear overpower 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 operating experience.

C.1

If the Required Actions and associated Completion Times of Condition B are not met, then the reactor will continue in power operation with significant QPT. Either the power level has not been reduced to comply with the Required Action or the nuclear overpower trip setpoint has not been reduced within the required Completion Time. To preclude risk of fuel damage in any of these conditions, THERMAL POWER is reduced further. Operation below 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 required Completion Time of 4 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.

D.1

QPT in excess of the maximum setpoint specified in the COLR 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 4 hours is reasonable to allow the operator to reduce THERMAL POWER to ≤ 20% RTP without challenging unit systems.

SURVEILLANCE REQUIREMENTS

QPT can be monitored by both the Incore and Excore Detector systems. The QPT setpoints are derived from their corresponding measurement system independent limits by adjustment for system observability errors and instrumentation errors. Although they may be based on the same measurement system independent limit, the limits for the different systems are not identical because of differences in the errors applicable for these systems. For QPT measurements using the Incore Detector System, the Minimum Incore Detector System consists of OPERABLE detectors configured as follows:

a. Two sets of four detectors shall lie in each core half. Each set of detectors shall lie in the same axial plane. The two sets in the same core half may lie in the same axial plane.

b. Detectors in the same plane shall have quarter core radial symmetry.

Figure B 3.2.4-1 (Minimum Incore Detector System for QPT Measurement) depicts an example of this configuration. The symmetric full Incore Detector System for QPT uses the Incore Detector System as described above and is configured such that at least 75% of the detectors in each core quadrant are OPERABLE.

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 and alarms 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 setpoint, operation at ≥ 95% RTP may proceed provided the QPT is determined to remain within the setpoint at the increased THERMAL POWER level. In case QPT exceeds the setpoint for more than 24 hours (Condition A), the potential for xenon redistribution is greater. Therefore, the QPT is monitored for 12 consecutive hourly intervals to determine whether the period of any oscillation due to xenon redistribution causes the QPT to exceed the setpoint again.

REFERENCES

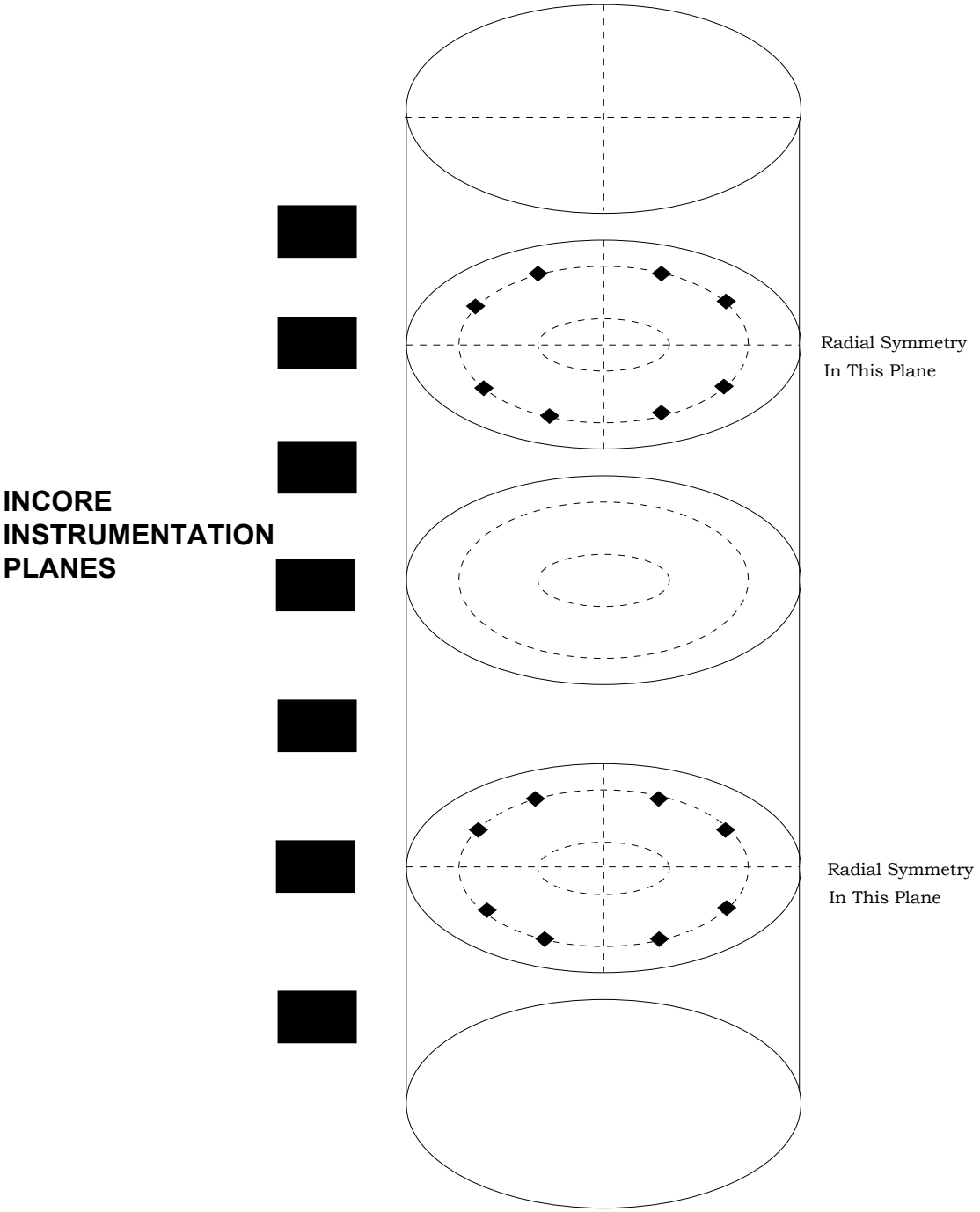
1. 10 CFR 50.46

2. BAW 10122A, "Normal Operating Controls," Rev. 1, May 1984.

3. 10 CFR 50.36

Figure B 3.2.4-1

Minimum Incore System for QUADRANT POWER Tilt Measurement



B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.5 Power Peaking

BASES

BACKGROUND

The purpose of this LCO is to establish limits that constrain the core power distribution within design limits during normal operation, during abnormalities and such that accident initial condition protection criteria are preserved. The accident initial condition criteria are preserved by bounding operation within specified acceptable fuel design limits. This is accomplished by limiting the local linear heat rate (LHR) to three general constraints: 1) the LHR may not exceed a value that results in fuel centerline melt, 2) the LHR may not exceed a value that would result in peak cladding temperatures of greater than 2200°F during a loss of coolant accident (LOCA), and 3) the LHR may not exceed a value that would result in the minimum departure from nucleate boiling ratio (DNBR) dropping below the specified acceptable fuel design limits in the event of the limiting loss of flow transient.

The LOCA-limited LHR is a specified acceptable fuel design limit that preserves the initial conditions for the Emergency Core Cooling Systems (ECCS) analysis. The LOCA-limited LHR is dependent upon core axial location and fuel batch design. The LOCA-limited LHR may be designated as LHR in units kW/ft or as a power peaking factor. When expressed as a power peaking factor, the LOCA-limited LHR is designated as $F_Q(Z)$. $F_Q(Z)$ 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. Operation within the limits given by the LOCA LHR figure in the COLR prevents power generation rates that would exceed the LOCA-limited LHR limits derived from the analysis of the ECCS.

The LOCA-limited LHR bounds the fuel centerline melt LHR limit. Thus, compliance with the LOCA-limited LHR ensures compliance with the fuel centerline melt LHR.

The DNBR-limited LHR is a specified acceptable fuel design limit that preserves the initial conditions for the limiting loss of flow transient. DNBR is defined as the ratio of the heat flux that would cause departure from nucleate boiling (DNB) at a particular core location to the actual heat flux at that core location. The DNBR-limited LHR represents the linear power generation rate along the fuel rod on which the minimum DNBR occurs. Compliance with this LHR value may be accomplished: 1) by correlating the LHR at the limiting location to the critical heat flux (expressed as a LHR) for the limiting location, 2) by correlating the LHR to DNBR or DNB margin for the limiting location, or 3) by correlating the LHR to a power peaking factor (designated as $F^N_{\Delta H}$) for the limiting location.

The relationship between the observable parameters of neutron power, reactor coolant flow, temperature and pressure and the critical heat flux, DNBR or DNB margin is provided through use of a critical heat flux correlation. The critical heat

BACKGROUND (continued)

flux correlations used to determine the critical heat flux for uniform and non-uniform heat flux distributions are described in the Bases for SL 2.1.1. $F^N_{\Delta H}$ is defined as the ratio of the integral of linear power along the fuel rod on which the minimum DNBR occurs to the average integrated rod power. Operation within the DNBR-limited LHR limit prevents DNB during a postulated loss of forced reactor coolant flow accident.

Measurement of the core peaking factors using the Incore Detector System to obtain a three dimensional power distribution map provides direct confirmation that LHRs are within their limits and may be used to verify that the core local LHRs remain bounded when one or more normal operating parameters exceed their limits.

APPLICABLE SAFETY ANALYSES

The LOCA-limited LHR limits 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 DNBR-limited LHR limits 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 heat flux that would cause DNB at a particular core location to the actual heat flux at that core location. 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. The critical heat flux correlations used to determine the critical heat flux for uniform and non-uniform heat flux distributions are described in the Bases for SL 2.1.1.

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

a. During a large break 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 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.

APPLICABLE SAFETY ANALYSES (continued)

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 as necessary through use of peaking augmentation factors in the reload safety evaluation analysis (Ref. 2).

LHR limitations satisfy Criterion 2 of 10 CFR 50.36 (Ref. 3).

LCO

This LCO for power peaking ensures that the core operates within the LHR bounds assumed for the ECCS and thermal hydraulic analyses. Verification that LHR is within the limits of this LCO as specified in the COLR allows continued operation when the Required Actions of LCO 3.1.4, “CONTROL ROD Group Alignment Limits,” LCO 3.2.1, “Regulating Rod Group Insertion Limits,” LCO 3.2.2, “APSR 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 LHR are exceeded. Verification that LHR is within the limits is also required during MODE 1 PHYSICS TESTS per LCO 3.1.8, “PHYSICS TESTS Exceptions - MODE 1.”

Measurement uncertainties are applied when LHR is determined using the Incore Detector System. The measurement uncertainties applied to the measured values account for uncertainties in observability and instrument string signal processing.

APPLICABILITY

In MODE 1 with THERMAL POWER > 20% RTP, the limits on LHR 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 forced reactor coolant flow accidents. In MODE 1 with THERMAL POWER ≤ 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.

APPLICABILITY (continued)

The minimum THERMAL POWER level of 20% RTP was chosen based on the ability of the incore detection system to satisfactorily obtain meaningful power distribution data.

ACTIONS

The operator must take care in interpreting the relationship of the LHRs, DNBRs, and power peaking factors to their limits. Limiting values may be expressed as an LHR, DNBR, margin to DNB or as power peaking factors. When expressed as power peaking factors, the value must be adjusted in inverse proportion to the THERMAL POWER level of the core as the power is reduced from RTP. Thus, the allowable peaking factors will increase as THERMAL POWER decreases.

A.1

When the LHR 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 limiting LHR in the core. The Completion Time of 2 hours provides an acceptable time to reduce power in an orderly manner and without allowing the unit to remain in an unacceptable condition for an extended period of time.

B.1

If the Required Action and associated Completion Time for Condition A are not met, then THERMAL POWER operation should be reduced. The reactor is placed in MODE 1 with THERMAL POWER less than or equal to 20% RTP where this LCO does not apply. The required Completion Time of 4 hours is a reasonable amount of time for the operator to reduce THERMAL POWER in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.5.1

Core power distribution monitoring is performed using the Incore Detector System to obtain a three dimensional power distribution map. Maximum LHR values obtained from this map may then be compared with the limits in the COLR to verify that the limits have not been exceeded. Minimum DNBR values or DNB margins determined from the core power distribution mapping may also be compared to their limits or correlated to LHR values to verify that the limits have not been exceeded. Measurement of the core power distribution in this manner may be used to verify that the measured LHR values remain within their specified limits when one or more

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.5.1 (continued)

of the limits specified by LCO 3.1.4, LCO 3.1.6, 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 the local LHRs 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 core power distribution) remain within their specified limits.

Because the limits on LHR are preserved when the parameters specified by LCO 3.1.4, LCO 3.1.6, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, or LCO 3.2.4 are within their limits, a Note is provided in the SR to indicate that monitoring core local LHRs 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 core local LHRs 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 LHR 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 3.1.6, LCO 3.2.1, LCO 3.2.2, LCO 3.2.3, or LCO 3.2.4 is permitted, because the core local LHRs assumed in the accident analyses are within analyzed core power distributions and spatial xenon distributions.

REFERENCES

1. 10 CFR 50.46.

2. BAW-10179P-A, “Safety Criteria and Methodology for Acceptable Cycle Reload Analyses,” Rev. 6, August 2005.

3. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor trip, if necessary, to protect against violating the core fuel design limits and the Reactor Coolant System (RCS) pressure boundary during abnormalities. By tripping the reactor, the RPS also assists the Engineered Safety Feature (ESF) Systems in mitigating accidents.

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

The LSSS, defined in this Specification as the Allowable Value, in conjunction with the LCOs and administrative controls, establishes the threshold for protective system action to prevent exceeding specified acceptable limits during Design Basis Accidents (DBAs). Acceptable consequences for accidents are that the offsite dose shall be maintained within 10 CFR 100 limits or other limits approved by the NRC. During abnormalities, one or more of the following limits is maintained:

a. For accidents other than locked rotor, the departure from nucleate boiling ratio (DNBR) shall be maintained above the Safety Limit (SL) value. For the locked rotor accident, the minimum DNBR shall not be less than the applicable critical heat flux correlation limit, or fuel cladding shall be shown to experience no significant temperature excursions;

b. Fuel centerline temperature shall be maintained below the SL value;

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

d. Reactor power shall not exceed 112% RTP.

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

<u>RPS Overview</u>

The RPS consists of four separate redundant protection channels that receive inputs of neutron flux, RCS pressure, RCS flow, reactor outlet temperature, RCS pump status, reactor building (RB) pressure, main feedwater (MFW) pump turbine status, and main turbine status.

BACKGROUND (continued)

Figure 7.1, SAR, Chapter 7 (Ref. 1), shows the arrangement of the RPS protection channels. A protection channel is composed of measurement channels, a manual trip channel, a reactor trip module (RTM), and control rod drive (CRD) trip devices. 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 RPS elements.

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 trip signals in any two of the four RPS channels will result in the trip of the reactor.

The Reactor Trip System (RTS) contains multiple CRD trip devices, two AC trip breakers, and two DC trip breaker pairs that provide a path for power to the CRD System. In addition to the safety rods, the power for the regulating rods and APSRs may be interrupted by the electronic trip assembly (ETA) relays. The system has two separate paths (or channels), with each path having either two breakers in series or a breaker and an ETA relay controlled silicon controlled rectifier (SCR) in series. Each path provides independent power to the CRDs. Either path can provide sufficient power to operate all CRDs. 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. Each 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 logic and to the two-out-of-four logic of the RTMs in the other three RPS channels. Whenever any two RPS channels trip, the RTM in each channel actuates to remove 120 VAC power from its associated CRD trip breaker.

The reactor is tripped by opening circuit breakers and de-energizing ETA relays that interrupt the control power supply to the CRDs. Six 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 RPS has two manual bypasses: a shutdown bypass and a channel bypass. Shutdown bypass allows the withdrawal of safety rods to provide the availability of rapidly insertable negative reactivity during unit cooldowns or heatups. Channel bypass is typically used for maintenance and testing. Test circuits in the trip strings allow testing of RPS trip Functions. Also, an automatic bypass is provided at low power levels for the Main Turbine Trip and the Loss of Main Feedwater Pump Functions.

BACKGROUND (continued)

The RPS receives input from the instrumentation channels discussed next. The specific relationship between measurement channels and protection channels differs from parameter to parameter.

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

Power Range Nuclear Instrumentation

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

1. Nuclear Overpower

    a. Nuclear Overpower - High Setpoint;

    b. Nuclear Overpower - Low Setpoint;

7. Reactor Coolant Pump to Power;

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE (Power Imbalance Flow);

9. Main Turbine Trip (Oil Pressure); and

10. Loss of Main Feedwater Pumps (Control Oil Pressure).

The Main Turbine Trip and Loss of Main Feedwater Pumps Functions utilize the Power Range Nuclear Instrumentation only for enabling/disabling the operating bypass at low power levels.

The power range instrumentation has four linear 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 top minus the bottom neutron signal is the measured AXIAL POWER IMBALANCE of the reactor core.

Reactor Outlet Temperature

The Reactor Outlet Temperature provides input to the following Functions:

2. Reactor Outlet High Temperature; and

5. RCS Variable Low Pressure.

BACKGROUND (continued)

The Reactor Outlet 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. RCS High Pressure;

4. RCS Low Pressure;

5. RCS Variable Low Pressure; and

11. Shutdown Bypass RCS 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.

Reactor Building Pressure

The Reactor Building Pressure measurements provide input only to the Reactor Building High Pressure trip, Function 6. There are four RB High Pressure sensors, one associated with each protection channel.

Reactor Coolant Pump Power Monitoring

Reactor coolant pump power monitors are inputs to the Reactor Coolant Pump to Power trip, Function 7. Each RCP's operating current is measured by a current transformer providing the current input to the associated RCP underpower relay, and the bus voltage is measured by a potential transformer providing the voltage input to the associated RCP underpower relays. Each RCP underpower relay provides individual RCP status to each protection channel.

Reactor Coolant System Flow

The Reactor Coolant System Flow measurements are an input to the Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip, Function 8. The reactor coolant flow inputs to the RPS are provided by eight differential pressure transmitters, four on each loop, which measure flow through calibrated flow tubes. One flow input in each loop is associated with each protection channel.

BACKGROUND (continued)

Main Turbine Automatic Stop Oil Pressure

Main Turbine Automatic Stop Oil Pressure is an input to the Main Turbine Trip (Oil Pressure) reactor trip, Function 9. Each of the four protection channels receives turbine status information from one of four pressure switches monitoring main turbine automatic stop oil pressure. Contact buffers in each protection channel continuously monitor the status of the contact inputs and initiate an RPS trip when a main turbine trip is indicated.

Feedwater Pump Control Oil Pressure

Feedwater Pump Control Oil Pressure is an input to the Loss of Main Feedwater Pumps (Control Oil Pressure) trip, Function 10. Control oil pressure is measured by four switches on each feedwater pump. One switch on each pump is associated with each protection channel.

RPS Bypasses

The RPS is designed with two types of manual 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. Each bypass is discussed next.

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. To place a protection channel in channel bypass, the key switch must be operated, and the other three channels must not be in channel bypass. This is ensured by contacts from the other channels being in series with the channel bypass relay. If any contact is open, the second channel cannot be bypassed. When the bypass relay is energized, the bypass contact closes, maintaining the channel trip relay in an energized condition. An indicator light remains lit while the channel is in bypass. All RPS trips are reduced to a two-out-of-three logic in channel bypass. Only one channel bypass key is accessible for use in the control room.

Shutdown Bypass

During unit cooldown, it is allowable to leave some safety rods withdrawn to provide shutdown capabilities in the event of unusual positive reactivity additions (moderator dilution, etc.).

BACKGROUND (continued)

However, the unit is also depressurized as coolant temperature is decreased. If the safety rods are withdrawn and coolant pressure is decreased, an RCS Low Pressure trip will occur at 1800 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 1800 psig. The RCS pressure is decreased to less than 1720 psig, then each RPS channel is placed in shutdown bypass.

When an RPS channel is placed in shutdown bypass, the RCS Low Pressure trip, Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip, Reactor Coolant Pump to Power trip, and the RCS Variable Low Pressure trip, are bypassed and a RCS High Pressure, ≤ 1720 psig trip and a Nuclear Overpower Low Setpoint trip, ≤ 5% RTP, are inserted. The operator can now withdraw the safety rods for additional rapidly insertable negative reactivity.

The insertion of the high pressure trip with a trip setpoint of ≤ 1720 psig prevents operation at normal system pressure, approximately 2155 psig, with a portion of the RPS bypassed, and ensures that the bypass is removed prior to normal operation. When the RCS pressure is increased during a unit heatup, the safety rods are inserted prior to reaching 1720 psig. The shutdown bypass is removed, which returns the RPS to normal, and system pressure is increased to greater than 1800 psig. All or some of the safety rods are then withdrawn and normally remain at the full out condition for the rest of the heatup.

The insertion of the Nuclear Overpower Low Setpoint Trip provides a backup to the Shutdown Bypass RCS High Pressure trip while preventing the generation of any significant amount of power.

Module Interlock and Test Trip Relay

Each channel and each trip module is capable of being individually tested. When a module is placed into the test mode, it causes the test trip relay to open and to indicate an RPS channel trip. Under normal conditions, the channel to be tested is placed in bypass before a module is tested.

Trip Setpoints/Allowable Value

The trip setpoints are the nominal 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 used in the safety analysis described in SAR, Chapter 14 and Chapter 3A (Ref. 2). The selection of these trip setpoints is such that adequate protection is provided when appropriate sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and

BACKGROUND (continued)

environment errors, the Allowable Values specified in Table 3.3.1-1 are equal to or conservatively adjusted with respect to the analytical limits. Guidance used to calculate the uncertainty associated with the trip setpoints is provided in Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001 (Ref. 3). The explicit uncertainties are addressed in the individual design calculations as required. The trip setpoint entered into the bistable may be more conservative than that specified by the Allowable Value to account for changes in instrument error detectable by a CHANNEL FUNCTIONAL TEST. A channel is inoperable if its as-found 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 abnormalities and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the abnormality or DBA and the equipment functions as analyzed. 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 trip setpoint are within the specified allowance requirements of approved calibration procedures. Once a designated channel is taken out of service for testing, a simulated signal may be injected in place of the field instrument signal. The process equipment for the channel may then be tested, verified, and calibrated.

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

Analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in the SAR, Chapter 14 and Chapter 3A (Ref. 2), takes credit for most RPS trip Functions. Functions not specifically credited in the accident analysis were qualitatively credited in the NRC staff approved licensing basis for the unit. These Functions are high RB pressure, high RCS temperature, turbine trip, loss of main feedwater, the shutdown bypass nuclear overpower low setpoint, and shutdown bypass high pressure. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions also serve as backups to Functions that were credited in the safety analysis.

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable. 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, the applicable RPS Functions must also be OPERABLE. 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

APPLICABLE SAFETY ANALYSES (continued)

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.

Required Actions allow maintenance (protection channel) bypass of individual channels, but the bypass activates interlocks that prevent operation with a second channel bypass. Bypass effectively places the unit in a two-out-of-three logic configuration that can still initiate a reactor trip, even with a single failure within the system.

Only the Allowable Values are specified for each RPS trip Function in the LCO. Trip setpoints are specified in the setpoint calculations or calibration procedures. The setpoints are selected such that the setpoint measured by CHANNEL FUNCTIONAL TESTS is not expected to exceed the Allowable Value if the bistable is performing as required.

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.

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 consequences of unit transients caused by the specific conditions. The Allowable Value for these Functions is selected at the specified deviation from normal values that will indicate the condition, without risking spurious trips due to normal fluctuations in the measured parameter.

The Allowable Values for bypass removal Functions are stated in the Applicable MODE or Other Specified Condition column of Table 3.3.1-1.

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

1. Nuclear Overpower

   a. Nuclear Overpower - High Setpoint

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

      The Nuclear Overpower - 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.

APPLICABLE SAFETY ANALYSES (continued)

Thus, the Nuclear Overpower - High Setpoint trip protects against violation of the DNBR and fuel centerline melt SLs. However, the RCS Variable Low Pressure, and Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE, also provide protection. The role of the Nuclear Overpower - High Setpoint trip is to limit reactor THERMAL POWER below the highest power at which the other two trips are known to provide protection.

The Nuclear Overpower - High Setpoint trip also provides transient protection for rapid positive reactivity excursions during power operations. These events include the rod withdrawal accident, the rod ejection accident, and the steam line break accident. By providing a trip during these events, the Nuclear Overpower - 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 Nuclear Overpower - High Setpoint trip provides the primary protection. At low reactivity insertion rates, the high pressure trip provides primary protection.

The specified Allowable Value is selected to initiate a trip at or before reactor power exceeds the highest point at which the RCS Variable Low Pressure and the Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trips are analyzed to provide protection against DNB and fuel centerline melt. The Allowable Value does not account for harsh environment induced errors, because the trip will actuate prior to degraded environmental conditions being reached.

b. Nuclear Overpower - Low Setpoint

While in shutdown bypass, the Nuclear Overpower - Low Setpoint is instated with a trip setpoint of $\leq$ 5% RTP. The low power setpoint, in conjunction with the Shutdown Bypass RCS High Pressure setpoint, protect the unit from excessive power conditions when other RPS trips are bypassed.

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

2. Reactor Outlet High Temperature

The Reactor Outlet High Temperature trip, in conjunction with the RCS Low Pressure and RCS Variable Low Pressure trips, provides protection for the DNBR SL. A trip is initiated whenever the reactor outlet temperature approaches the conditions necessary for DNB. Portions of each Reactor

APPLICABLE SAFETY ANALYSES (continued)

Outlet High Temperature trip channel are common with the RCS Variable Low Pressure trip. The Reactor Outlet High Temperature trip provides steady state protection for the DNBR SL.

The Reactor Outlet High Temperature trip limits the maximum RCS temperature to below the highest value for which DNB protection by the Variable Low Pressure trip is ensured. The trip setpoint Allowable Value is selected to initiate a trip before hot leg temperatures reach the point beyond which the RCS Low Pressure and Variable Low Pressure trips are analyzed. Above the high temperature trip, the variable low pressure 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 will actuate prior to degraded environmental conditions being reached.

3. RCS High Pressure

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

The RCS High Pressure trip has been credited in the accident analysis calculations for slow positive reactivity insertion transients (rod withdrawal accidents and moderator dilution). The rod withdrawal accidents cover a large spectrum of reactivity insertion rates and rod worths that exhibit slow and rapid rates of power increases. At high reactivity insertion rates, the Nuclear Overpower - High Setpoint trip provides the primary protection. At low reactivity insertion rates, the RCS High Pressure trip provides the primary protection.

The Allowable Value is selected such that the RCS High Pressure SL is not exceeded during steady state operation or slow power increasing transients. The Allowable Value does not reflect errors induced by harsh environmental conditions because the trip will actuate prior to degraded environmental conditions being reached.

4. RCS Low Pressure

The RCS Low Pressure trip, in conjunction with the Reactor Outlet High Temperature and Variable Low Pressure trips, provides protection for the DNBR SL. A trip is initiated prior to reactor outlet temperature exceeding the conditions necessary for DNB. The RCS Low Pressure trip provides the DNB low pressure limit for the RCS Variable Low Pressure trip.

The RCS Low Pressure Allowable Value is selected to initiate a reactor trip before RCS pressure is reduced below the lowest point at which the RCS Variable Low Pressure trip is analyzed. The RCS Low Pressure trip provides protection for primary system depressurization events and has been credited in

APPLICABLE SAFETY ANALYSES (continued)

the accident analysis calculations for small break loss of coolant accidents (LOCAs). The Allowable Value does not reflect errors induced by harsh environmental conditions that the equipment is expected to experience because either the trip will actuate prior to degraded conditions being reached or the equipment response will be conservative.

5. RCS Variable Low Pressure

The RCS Variable Low Pressure trip, in conjunction with the Reactor Outlet High Temperature and RCS Low Pressure trips, provides protection for the DNBR SL. A trip is initiated prior to the system parameters of pressure and temperature exceeding the conditions necessary for DNB. The RCS Variable Low Pressure trip provides a floating low pressure trip based on the reactor outlet temperature expressed in degrees Fahrenheit within the range specified by the Reactor Outlet High Temperature and RCS Low Pressure trips.

The RCS Variable Low Pressure Allowable Value is selected to initiate a trip prior to temperature and pressure exceeding the conditions necessary for DNB while operating in a temperature pressure region constrained by the low pressure and high temperature trips. The RCS Variable Low Pressure trip is not assumed for transient protection in the unit safety analysis. Therefore, the Allowable Value does not account for errors induced by a harsh RB environment.

6. Reactor Building High Pressure

The Reactor Building High Pressure trip provides an early indication of a high energy line break (HELB) inside the RB. By detecting changes in the RB pressure, the RPS can provide a reactor trip before the other system parameters have varied significantly. Thus, this trip acts to minimize accident consequences.

The Allowable Value for RB High Pressure trip is set at the lowest value consistent with avoiding spurious trips during normal operation. Even in the case where this trip is a backup for other RPS trips for LOCA or MSLB, it is assumed to occur before degraded building conditions have an appreciable effect on RB High Pressure trip components. Therefore, determination of the Allowable Value does not account for errors induced by a harsh environment.

7. Reactor Coolant Pump to Power

The Reactor Coolant Pump to Power trip provides protection for changes in the reactor coolant flow due to the loss of multiple 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.

APPLICABLE SAFETY ANALYSES (continued)

The trip also prevents operation with both pumps in either coolant loop tripped. Under these conditions, core flow and core fluid mixing may be insufficient for adequate heat transfer. Thus, the Reactor Coolant Pump to Power trip functions to protect the DNBR and fuel centerline temperature SLs.

The Reactor Coolant Pump to Power trip has been credited in the accident analysis calculations for the loss of four RCPs. The trip also provides protection for the loss of a pump or pumps which would result in both pumps in a single steam generator loop being tripped.

The Allowable Value for the Reactor Coolant Pump to Power trip setpoint is selected to prevent normal power operation unless at least one RCP is operating in each loop. RCP status is monitored by power transducers associated with each pump. These relays indicate a loss of an RCP on underpower. The underpower Allowable Value is selected to reliably trip on loss of voltage to the RCPs. Neither the reactor power nor the pump power Allowable Value 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. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE

The Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip provides steady state protection for the reactor core SLs. A reactor trip is initiated prior to the core power, AXIAL POWER IMBALANCE, and reactor coolant flow conditions exceeding the DNB or fuel centerline temperature limits.

This trip supplements the protection provided by the Reactor Coolant Pump to Power trip, through the power to flow ratio, for loss of reactor coolant flow events. The power to flow ratio provides direct protection for the limiting loss of flow transient which is the loss of two RCPs from four pump operation. The imbalance portion of the trip is credited for steady state protection only.

The power to flow ratio of the Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip also provides steady state protection to prevent reactor power from exceeding the allowable power when the primary system is operating with two or three pump flow. Thus, the power to flow ratio prevents overpower conditions similar to the Nuclear Overpower 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 prior to core power, axial power peaking, and reactor coolant flow conditions reaching DNB or fuel centerline temperature limits. The Allowable Value for this Function is given in the unit COLR because the cycle specific core peaking changes affect the Allowable Value.

APPLICABLE SAFETY ANALYSES (continued)

9. Main Turbine Trip (Oil Pressure)

The Main Turbine Trip Function trips the reactor when the main turbine is tripped at high power levels. The Main Turbine Trip Function provides an early reactor trip in anticipation of the loss of heat sink associated with a turbine trip. The Main Turbine Trip Function was added to the B&W designed units in accordance with NUREG-0737 (Ref. 4) following the Three Mile Island Unit 2 accident. The trip lowers the probability of an RCS electromatic relief valve (ERV) actuation for turbine trip cases.

Each of the four turbine oil pressure switches feeds one of the four protection channels through a buffer that continuously monitors the status of the contacts. Therefore, failure of any pressure switch affects only one protection channel.

For the Main Turbine Trip (Oil Pressure) bistable, the Allowable Value of ≥ 40.5 psig is selected to provide a trip whenever main turbine oil pressure drops below the normal operating range. The reactor power bypass is designed to automatically remove the turbine oil pressure trip function from the bypassed condition at < 45% RTP. Alarms are available to alert operators when the bypass function is enabled. Should the automatic bypass removal function fail such that the channel remains in the bypassed state, the channel must be considered inoperable at power levels of ≥ 45% RTP and the appropriate condition is entered. Failure of the automatic bypass removal feature alone or the inability to place the channel in a bypassed state when < 45% RTP does not constitute channel inoperability. The automatic bypass removal feature is tested to ensure its continued availability during the monthly CHANNEL FUNCTIONAL TEST. The turbine trip is not required to protect against events that can create a harsh environment in the turbine building. Therefore, errors induced by harsh environments are not included in the determination of the setpoint Allowable Value.

10. Loss of Main Feedwater Pumps (Control Oil Pressure)

The Loss of Main Feedwater Pumps (Control Oil Pressure) trip provides a reactor trip at high power levels when both MFW pumps are tripped. The trip provides an early reactor trip in anticipation of the loss of heat sink associated with a loss of main feedwater. This trip was added in accordance with NUREG-0737 (Ref. 4) following the Three Mile Island Unit 2 accident. This trip provides a reactor trip for a loss of main feedwater to minimize challenges to the ERV.

For the feedwater pump control oil pressure bistable, the Allowable Value of ≥ 55.5 psig is selected to provide a trip whenever feedwater pump control oil pressure drops below the normal operating range. The reactor power bypass is designed to automatically remove the main feedwater pump oil pressure trip function from the bypassed condition at < 10% RTP. Alarms are available to

APPLICABLE SAFETY ANALYSES (continued)

alert operators when the bypass function is enabled. Should the automatic bypass removal function fail such that the channel remains in the bypassed state, the channel must be considered inoperable at power levels of ≥ 10% RTP and the appropriate condition is entered. Failure of the automatic bypass removal feature alone or the inability to place the channel in a bypassed state when < 10% RTP does not constitute channel inoperability. The automatic bypass removal feature is tested to ensure its continued availability during the monthly CHANNEL FUNCTIONAL TEST. The Loss of Main Feedwater Pumps (Control Oil Pressure) trip is not required to protect against events that can create a harsh environment in the turbine building. Therefore, errors caused by harsh environments are not included in the determination of the setpoint Allowable Value.

11. Shutdown Bypass RCS High Pressure

The RPS Shutdown Bypass is provided to allow for withdrawing the CONTROL RODS while operating below the normal RCS Low Pressure trip setpoint. The shutdown bypass allows the operator to withdraw the safety groups of CONTROL RODS. This makes their negative reactivity available to terminate inadvertent reactivity excursions. Because the shutdown bypass high pressure trip setpoint is below the normal RCS low pressure trip setpoint, the reactor must be tripped while passing between these two setpoints. This ensures that RPS trips cannot be bypassed unless the CONTROL RODS are all inserted.

Accidents analyzed in the SAR, Chapter 14 and Chapter 3A (Ref. 2), do not include events that occur during shutdown bypass operation.

During shutdown bypass operation with the Shutdown Bypass RCS High Pressure trip active with a setpoint of ≤ 1720 psig and the Nuclear Overpower - Low Setpoint active with a setpoint of ≤ 5% RTP, the trips listed below are bypassed.

4. RCS Low Pressure;

5. RCS Variable Low Pressure;

7. Reactor Coolant Pump to Power; and

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE.

The Shutdown Bypass Nuclear Overpower - Low Setpoint Allowable Value is selected to initiate a trip before producing significant THERMAL POWER.

APPLICABLE SAFETY ANALYSES (continued)

General Discussion

In MODES 1 and 2, the RPS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODES 3, 4, and 5 with any CRD trip breaker in the closed position and the CRD System capable of rod withdrawal, the RPS satisfies Criterion 4 of 10 CFR 50.36.

In MODE 1; in MODE 2, when not operating in shutdown bypass; and 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 following trips are required to be OPERABLE. These trips function to ensure that any withdrawn CONTROL RODS can be automatically inserted to make or maintain the reactor subcritical.

1.a. Nuclear Overpower-High Setpoint; and

3. RCS High Pressure.

In MODES 1 and 2, the following trips are required to the OPERABLE. These trips function as primary or as back-up trips to ensure that any withdrawn CONTROL RODS can be automatically inserted to make or maintain the reactor subcritical.

2. Reactor Outlet High Temperature; and

6. Reactor Building High Pressure.

In addition, Function 6, Reactor Building High Pressure, is required to be OPERABLE in MODE 3, whenever any CRD trip breaker is closed and the CRD system is capable of rod withdrawal. In this MODE, this Function serves purely as a back-up to other required Functions.

In MODE 1 and in MODE 2, when not in shutdown bypass operation, the following trips are required to be OPERABLE. These Functions operate to ensure that any withdrawn CONTROL RODS can be automatically inserted to make or maintain the reactor subcritical. These functions are all bypassed when the channel is placed in a shutdown bypass condition. Therefore, they are not required to be OPERABLE during shutdown bypass operation.

4. RCS Low Pressure;

5. RCS Variable Low Pressure;

7. Reactor Coolant Pump to Power; and

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE.

Two Functions are required to be OPERABLE only during portions of MODE 1. These are the Main Turbine Trip (Oil Pressure) and the Loss of Main Feedwater Pumps (Control Oil Pressure) trip. These Functions are required to be OPERABLE

APPLICABLE SAFETY ANALYSES (continued)

at ≥ 45% RTP and ≥ 10% RTP, respectively. Analyses presented in BAW-1893 (Ref. 6) have shown that for operation below these power levels, these trips are not necessary to minimize challenges to the ERV as required by NUREG-0737 (Ref. 4).

Because the 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 either 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 because the CONTROL RODS are normally decoupled from the CRDs.

However, during shutdown bypass operation, in MODE 2, 3, 4, or 5, the Shutdown Bypass RCS High Pressure and Nuclear Overpower - 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 RCS High Pressure and Nuclear Overpower - Low setpoint trips sufficiently reduce the potential for 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 nonconservative 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 all applicable Conditions entered immediately.

A.1 and A.2

If one or more Functions in one protection channel become inoperable, the affected protection channel must be placed in bypass or trip, or the bypass of the remaining channels prevented. 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.

Another option is to maintain the channel, which contains one or more inoperable Functions, in an untripped and unbypassed state. In this case, bypass of the remaining three channels must be prevented. This is accomplished by tagging them, under administrative controls, to prevent their being bypassed. This option assumes that the inoperability of the Function(s) does not require the channel containing the inoperable Function(s) to remain in a tripped condition, and that the channel contains other Functions which remain OPERABLE.

ACTIONS (continued)

A.1 and A.2 (continued)

By maintaining the channel in an untripped and unbypassed state, the inoperable Function (s) are in a two-out-of-three logic configuration. This configuration is equivalent to bypassing the channel. However, by maintaining the channel in an untripped and unbypassed condition, the OPERABLE Functions within that channel remain in service in a normal two-out-of-four logic configuration.

Operation in these configurations may continue indefinitely because 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 or Required Action A.2.

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

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. The second inoperable channel may be bypassed or may be maintained in an untripped and unbypassed condition. If the channel is not bypassed, bypass of the remaining channels must be prevented. This is accomplished by tagging them, under administrative controls, to prevent their being bypassed. This option assumes that the inoperability of the Function(s) in the second channel does not require that channel to remain in a tripped condition, and that the channel contains one or more Function(s) which remains OPERABLE. These Required Actions place all RPS Functions in either a one-out-of-two or one-out-of-three logic configuration. In either of these configurations, 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, Required Action B.2.1, and Required Action B.2.2.

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 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.

D.1 and D.2

If Required Action C.1 and Table 3.3.1-1 direct 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 unit systems.

ACTIONS (continued)

E.1

If Required Action C.1 and Table 3.3.1-1 direct entry into Condition E, the unit must be brought to a MODE 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 unit systems.

F.1

If Required Action C.1 and Table 3.3.1-1 direct entry into Condition F, the unit must be brought to a MODE in which the specified RPS trip Function is not required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 45% RTP. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach 45% RTP from full power conditions in an orderly manner without challenging unit systems.

G.1

If Required Action C.1 and Table 3.3.1-1 direct entry into Condition G, the unit must be brought to a MODE in which the specified RPS trip Function is not required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 10% RTP. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach 10% RTP from full power conditions in an orderly manner without challenging unit systems.

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, and CHANNEL CALIBRATION testing.

The SRs are modified by a Note which 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 provides reasonable assurance of prompt identification of a gross failure of instrumentation. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to the same 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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1 (continued)

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 factors including channel instrument uncertainties. 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, where practical, verified to be reading at the bottom of the range and not failed downscale.

The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. For example, during a power increase near the top of the scale for the intermediate range monitors, a power range monitor reading is expected with at least one decade overlap. Without such an overlap, the power range monitors are considered inoperable unless it is clear that an intermediate range monitor inoperability is responsible for the lack of the expected overlap.

The Frequency 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 Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE Function, 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 96 hours and once within 24 hours after a THERMAL POWER change of ≥ 10% RTP in one direction, when reactor power is ≥ 20% 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 calibrated to the calorimetric. Note 1 to the SR states if the absolute difference between the calorimetric and the Nuclear Instrumentation System (NIS) channel is

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2 (continued)

> 2% RTP, the NIS channel 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 ≥ 20% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 20% RTP.

Two calorimetric calculations are routinely performed. One relies upon primary system parameters and the other relies upon secondary system parameters. The primary calorimetric is generally less accurate than the secondary calorimetric at higher power levels and more accurate at lower power levels. For comparison to the nuclear instrumentation, between 0 and 15% power, only the primary calorimetric (heat balance) is considered. From 15 to 100% power the calorimetric is weighted linearly with only the secondary heat balance being considered at 100% power.

The power range channel's output shall be adjusted consistent with the calorimetric results if the absolute difference between the calorimetric and the power range channel's output is > 2% RTP. The value of 2% is adequate because this value is assumed in the safety analyses of SAR, Chapter 14 (Ref. 2). These checks and, if necessary, the adjustment of the power range channels ensure that channel accuracy is maintained within the analyzed error margins. The 96 hour Frequency is adequate, based on unit operating experience, which demonstrates the change in the difference between the power range indication and the calorimetric results rarely exceeds 2% in any 96 hour period. Furthermore, the control room operators monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

A comparison of power range nuclear instrumentation channels against incore detectors shall be performed at a 31 day Frequency when reactor power is ≥ 20% RTP. The SR is modified by two Notes. Note 2 clarifies that 24 hours is allowed for performing the first Surveillance after reaching 20% RTP. Note 1 states if the absolute difference between the power range and incore AXIAL POWER IMBALANCE measurements is ≥ 2% RTP, 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 AXIAL POWER IMBALANCE measurements of 2.5%. Additional inaccuracies beyond those that are measured are also included in the setpoint envelope calculation. The 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

A CHANNEL FUNCTIONAL TEST is performed to ensure that the entire channel will perform the intended function. 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 setpoint analysis.

The Frequency of 31 days is based on operating experience, which has demonstrated through high reliability of the instrumentation, that failure of more than one channel, of a given Function, in any 31 day interval is rare.

Testing in accordance with this SR is normally performed on a rotational basis, with one channel being tested each week. Testing one channel each week reduces the probability of an undetected failure existing within the system and minimizes the likelihood of the same systematic test errors being introduced into each redundant channel. The automatic bypass removal feature is verified for the turbine oil pressure trip and the main feedwater pump oil pressure trip functions during the CHANNEL FUNCTIONAL TEST.

SR 3.3.1.5

A 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.

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 instrument errors are within the assumptions of the setpoint analysis. CHANNEL CALIBRATION must be performed consistent with the assumptions of the setpoint analysis. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

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

REFERENCES

1. SAR, Chapter 7.

2. SAR, Chapter 14 and Chapter 3A.

3. Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001.

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

5. 10 CFR 50.36.

6. BAW-1893, "Basis for Raising Arming Threshold for Anticipatory Reactor Trip on Turbine Trip," October 1985.

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, or coincident with, any other trip condition. Manual trip is provided by a trip push button on the main control board. This push button operates four electrically independent switches. This trip is independent of the automatic trip system. Control power for the control rod drive (CRD) breakers and electronic trip assembly (ETA) relays comes from the reactor trip modules (RTMs). The manual trip switches are located between the RTM output and the breaker undervoltage coils, breaker undervoltage relays, and ETA relays. The switches also initiate actuation of the breaker shunt trip mechanisms. These are separate switches which are actuated through a mechanical linkage from a single push button. Opening of the switches opens the circuits to the breakers, tripping them.

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 Function is required as a backup to the automatic trip functions.

Operating experience has shown the Manual Reactor Trip Function to be significant to public health and safety, and therefore satisfy Criterion 4 of 10 CFR 50.36 (Ref. 2).

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 CRD 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 four electrically independent trip switches sharing a common mechanical push button.

APPLICABILITY

The Manual Reactor Trip Function is required to be OPERABLE in MODES 1 and 2. It is 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 primary safety function of the RPS is to trip the CONTROL RODS; therefore, the Manual Reactor Trip Function is 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 is not needed in MODE 6 because the CONTROL RODS are normally decoupled from the CRDs.

ACTIONS

A.1

Condition A applies when the Manual Reactor Trip Function is found inoperable. One hour is allowed to restore the Function 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.

B.1 and B.2

If the Required Action and associated Completion Time are not met in MODE 1, 2, or 3, the unit must be placed in a MODE in which manual trip is not required. Required Action B.1 and Required Action B.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.

C.1

If the Required Action and associated Completion Time are not met in MODE 4 or 5, the unit must be placed in a MODE 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.

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 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 this Surveillance is only performed during a unit outage.

REFERENCES

1. SAR, Chapter 7.

2. 10 CFR 50.36.

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. 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, two channel trips caused by different trip functions can result in a reactor trip.

APPLICABLE SAFETY ANALYSES

Accident analyses rely on a reactor trip for protection of reactor core integrity, reactor coolant pressure boundary integrity, and reactor building OPERABILITY. 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."

In MODES 1 and 2, the RTMs satisfy Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODES 3, 4, and 5 with any CRD trip breaker in the closed position and the CRD System capable of rod withdrawal, the RTMs satisfy Criterion 4 of 10 CFR 50.36.

LCO

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

To be considered OPERABLE, an RTM must be able to receive and interpret trip signals from its own and other OPERABLE RPS channels and to open its associated trip device.

The requirement for four channels to be OPERABLE ensures that a minimum of two RPS channels will remain OPERABLE if a single failure has occurred in one channel and if a second channel has been bypassed. This two-out-of-four trip logic also ensures that a single RPS channel 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. This need may exist in any 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 opening (tripping) the

ACTIONS (continued)

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

CRD trip breaker or by removing power to the CRD trip device. Tripping one RTM or removing power opens one set of CRD trip devices. 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 second protection channel trips.

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 two or more RTMs are inoperable in MODE 1, 2, or 3, or if the Required Actions and associated Completion Time of Condition A are not met in MODE 1, 2, or 3. In this case, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 with all CRD trip breakers open or with power to 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 two or more RTMs are inoperable in MODE 4 or 5, or if the Required Actions and associated Completion Times are not met in MODE 4 or 5. In this case, the unit must be placed in a MODE 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 all power to the CRD System without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1

The SRs include performance of a CHANNEL FUNCTIONAL TEST every 92 days. This test shall verify the OPERABILITY of the RTM and its ability to receive and properly respond to channel trip and reactor trip signals.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.1 (continued)

The Frequency of 92 days is based on operating experience, which has demonstrated through high reliability of the instrumentation, that failure of more than one RTM in any 92 day interval is rare (Ref. 3).

Testing in accordance with this SR is normally performed on a rotational basis, with one RTM being tested each 23 days. Testing one RTM each 23 days reduces the probability of an undetected failure existing within the system and minimizes the likelihood of the same systematic test errors being introduced into each redundant RTM.

REFERENCES

1. SAR, Chapter 7.

2. 10 CFR 50.36.

3. BAW-10167A, “Justification for Increasing the Reactor Trip System On-Line Test Intervals,” Supplement 3, “Justification for Increasing the Trip Device Test Interval,” February 1998.

B 3.3 INSTRUMENTATION

B 3.3.4 Control Rod Drive (CRD) Trip Devices

BASES

BACKGROUND

The Reactor Protection System (RPS) contains multiple CRD trip devices: two AC trip breakers, two DC trip breaker pairs, and ten electronic trip assembly (ETA) relays. The system has two separate paths (or channels), with each path having one AC breaker either in series with a pair of DC breakers or functionally in series with five ETA relays in parallel. Each path provides independent power to the CRDs. Either path can provide sufficient power to operate the entire CRD System.

Figure 7-10 SAR, Chapter 7 (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. These breakers are designated A and B, and their undervoltage and shunt trip coils are controlled by RPS channels A and B, respectively. From the circuit breakers, the CRD power travels through voltage regulators and stepdown transformers. These devices in turn supply redundant buses that feed the DC holding power supplies and the regulating rod, APSR and auxiliary power supplies.

The DC holding power supplies rectify the AC input and supply power to hold the safety rods in their fully withdrawn position. One of the redundant power sources supplies phase A; the other, phase CC. Either phase being energized is sufficient to hold the rod. Two breakers are located on the output of each power supply. Each breaker controls half of the power to two of the four safety rod groups. The undervoltage and shunt trip coils on the two circuit breakers on the output of one of the power supplies is controlled by RPS channel C. The other two breakers are controlled by RPS channel D.

In addition to the DC holding power supplies, the redundant buses also supply power to the regulating rod, APSR and auxiliary power supplies. These power supplies contain silicon controlled rectifiers (SCRs), which are gated on and off to provide power to, and remove power from, the phases of the CRD mechanisms. The gating control signal for these SCRs is supplied through the closed contacts of the ETA relays. These contacts are referred to as E and F contactors, and are controlled by the C and D RPS channels, respectively.

The AC breaker and DC breakers, or gated SCRs, are in series in one of the power supplies; whereas, the redundant AC breaker and DC breakers or gated SCRs are in series in the other power supply to the CONTROL RODS. The logic required to

BACKGROUND (continued)

cause a reactor trip is the opening of a circuit breaker or ETA relay in each of the redundant power supplies. (The pair of DC circuit breakers on the output of the power supply are treated as one breaker.) This is known as a one-out-of-two taken twice logic. The following examples illustrate the operation of the reactor trip circuit breakers.

a. If the A AC circuit breaker opens:

   1. the input power to associated DC power supply is lost, and

   2. the SCR supply from the associated power source is lost.

b. If the D DC circuit breaker(s) and F contactors open:

   1. the output of the redundant DC power supply is lost and the safety rods de-energize, and

   2. when the F contactor opens, SCR gating power is lost and the regulating rods will be de-energized.

c. The combination of (a) and (b) causes a reactor trip.

Any other combination of at least one circuit breaker opening in each power supply will cause a reactor trip.

In summary, two tripped RPS channels will cause a reactor trip. For example, a reactor trip occurs if RPS channel B senses a low Reactor Coolant System (RCS) pressure condition and if RPS channel C senses a variable low RCS pressure condition. When the channel B bistable relay de-energizes, the channel trip relay de-energizes and opens its associated contacts. The same thing occurs in channel C, except the variable low pressure bistable relay de-energizes the channel C trip relay. When the output logic relays in channels B and C de-energize, the B and C contacts in the trip logic of each channel's reactor trip module (RTM) open causing an undervoltage to each trip breaker. All trip breakers and the ETA relay contactors open, and power is removed from all CRD mechanisms. All rods fall into the core, resulting in a reactor trip.

APPLICABLE SAFETY ANALYSES

Accident analyses rely on a reactor trip for protection of reactor core integrity, reactor coolant pressure boundary integrity, and reactor building OPERABILITY. 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

APPLICABLE SAFETY ANALYSES (continued)

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

In MODES 1 and 2, the CRD trip devices satisfy Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODES 3, 4, and 5 with any CRD trip breaker in the closed position and the CRD System capable of rod withdrawal, the CRD trip devices satisfy Criterion 4 of 10 CFR 50.36.

LCO

The LCO requires all of the specified CRD trip devices to 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. Failure of any required CRD trip device renders a portion of the RPS inoperable. Without reliable CRD reactor trip circuit breakers and associated support circuitry, a reactor trip may not occur when initiated either automatically or manually.

All required 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 power to the CRDs. Both of a CRD trip breaker's diverse trip devices and the breaker itself must be functioning properly for the breaker to be OPERABLE.

Both ETA relays associated with each of the three regulating rod groups and the two ETA relays associated with the auxiliary power supply must be OPERABLE to satisfy the LCO. The ETA relays associated with the APSR power supply are not required to be OPERABLE because the APSRs are not designed to fall into the core upon initiation of a reactor trip.

Requiring all breakers and ETA relays 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.

APPLICABILITY

The CRD trip devices are required to 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. Since a trip may be required in all of these MODES, the CRD trip devices must 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) or breaker pair; or
- One diverse trip Function is inoperable in both DC trip breakers associated with one protection channel. In this case, the inoperable trip Function does not need to be the same for both breakers.

If one of the diverse trip Functions on a CRD trip breaker or breaker pair 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 opening the inoperable CRD trip breaker or by removing power from 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 both diverse trip Functions are inoperable in one or more trip breaker(s) or breaker pairs.

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 open 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, C.3, and C.4

Condition C represents a loss of redundancy for the CRD trip Function. Condition C applies when one or more ETA relays are inoperable. The preferred action is to restore the ETA relay to OPERABLE status. If this cannot be done, the operator can perform one of four actions to eliminate reliance on the failed ETA relay. The first option is to switch the affected CONTROL ROD group to an alternate power supply which has two OPERABLE or one OPERABLE and one open ETA relay.

ACTIONS (continued)

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

This removes the failed ETA relay from the trip sequence, and the unit can operate indefinitely. The second option is to transfer the affected CONTROL ROD group to a DC holding power supply. This option is only available if the affected group is a safety rod group and the affected power supply is the auxiliary power supply. The third option is to open the inoperable ETA contacts. This option results in the safety function being performed. The fourth option is to open the corresponding AC CRD trip breaker. This also results in the safety function being performed, thereby eliminating the failed ETA relay from the trip sequence.

The 1 hour Completion Time is sufficient to perform the Required Action.

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

If the Required Actions and associated Completion Times of Condition A, B, or C are not met in MODE 1, 2, or 3, 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, with all CRD trip breakers open or with power to 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.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, or C are not met in MODE 4 or 5, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, all CRD trip breakers must be opened or power to 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 is to perform a CHANNEL FUNCTIONAL TEST every 92 days. 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 trip breakers. The Frequency of 92 days is based on operating experience, which has demonstrated that failure of more than one channel of a given function in any 92 day interval is a rare event (Ref. 3).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1 (continued)

Testing in accordance with this SR is normally performed on a rotational basis with one channel being tested each 23 days. Testing one channel each 23 days reduces the probability of an undetected failure existing within the system and minimizes the likelihood of the same systematic test errors being introduced into each redundant trip device.

REFERENCES

1. SAR, Chapter 7.

2. 10 CFR 50.36.

3. BAW-10167A, “Justification for Increasing the Reactor Trip System On-Line Test Intervals,” Supplement 3, “Justification for Increasing the Trip Device Test Interval,” February 1998.

B 3.3 INSTRUMENTATION

B 3.3.5 Engineered Safeguards Actuation System (ESAS) Instrumentation

BASES

BACKGROUND

The ESAS initiates necessary safety systems, based on the values of selected unit Parameters, to protect against violating core design limits and to mitigate accidents.

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

Three Parameters are used for actuation:

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

LCO 3.3.5 covers only the analog instrument channels that measure these Parameters. These channels include the equipment necessary to produce an actuation signal input to the digital actuation logic channels. This includes sensors, bistable devices, operational bypass circuitry, and logic buffer modules. LCO 3.3.6, "Engineered Safeguards Actuation System (ESAS) Manual Initiation," and LCO 3.3.7, "Engineered Safeguards Actuation System (ESAS) Actuation Logic," provide requirements on the manual initiation and digital actuation logic Functions.

The ESAS monitors three parameters via analog instrument channels. Each analog instrument channel provides input to the appropriate digital actuation logic channels that initiate equipment with a two-out-of-three coincidence logic on each digital channel. Each digital actuation logic channel includes bistable inputs from all three analog instrument channels of one parameter, i.e., either Low RCS Pressure, High RB Pressure, or High High RB Pressure. The digital actuation logic combines the analog instrument channel trips to actuate the individual Engineered Safeguards (ES) components needed to initiate each ES System. Figure 7.6, SAR, Chapter 7 (Ref. 1), also illustrates how analog instrument channel trips combine to cause digital actuation logic channel trips.

The ESAS is divided into five Functions actuated by ten digital actuation logic channels.

BACKGROUND (continued)

The ESAS High Pressure Injection (HPI) Function is actuated by ESAS digital actuation logic channels 1 and 2 and includes the following system actuations: HPI, a subset of RB isolation valves, diesel generators (DGs), and ES electrical alignment. Digital actuation logic channels 1 and 2 are actuated by two-out-of-three RCS Pressure—Low analog instrument channels, or two-out-of-three RB Pressure—High analog instrument channels.

The ESAS Low Pressure Injection (LPI) Function is actuated by ESAS digital actuation logic channels 3 and 4 and includes the following system actuations: LPI, a subset of RB isolation valves, and emergency feedwater (EFW) through an ESAS signal provided to the Emergency Feedwater Initiation and Control (EFIC) Instrumentation System. Digital actuation logic channels 3 and 4 are actuated by two-out-of-three RCS Pressure—Low analog instrument channels, or two-out-of-three RB Pressure—High analog instrument channels.

The ESAS RB Cooling Function is actuated by ESAS digital actuation logic channels 5 and 6 and includes the following system actuations: RB cooling, a subset of RB isolation valves, and RB penetration room ventilation system. Digital actuation logic channels 5 and 6 are actuated by two-out-of-three RB Pressure—High analog instrument channels.

The ESAS RB Spray Function is actuated by ESAS digital actuation logic channels 7 and 8 and includes the following system actuations: RB spray. Digital actuation logic channels 7 and 8 are actuated by two-out-of-three RB Pressure—High High analog instrument channels.

The ESAS Spray Additive Function is actuated by ESAS digital actuation logic channels 9 and 10 and includes the following system actuations: spray additive. Digital actuation logic channels 9 and 10 are actuated by two-out-of-three RB Pressure—High High analog instrument channels.

The following matrix identifies the ESAS digital actuation logic channels and the systems actuated by each Parameter.

ESAS Digital Actuation Logic Channels	Actuated Systems	Parameter		
		RCS Press. Low	RB Press. High	RB Press. High High
1 and 2	Subset of RB Isolation, ES Electrical Alignment, HPI, and DG Start	X	X	
3 and 4	Subset of RB isolation, LPI, and EFIC EFW	X	X	
5 and 6	Subset of RB Isolation, RB Cooling, and Penetration Room Ventilation		X	
7 and 8	RB Spray			X
9 and 10	Spray Additive			X

BACKGROUND (continued)

The ES equipment is divided between the two redundant actuation trains. 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 digital actuation logic channels and the related safeguards equipment will not inhibit the overall ES Functions. Redundant ES pumps are controlled from separate and independent digital actuation logic channels.

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

The ESAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents (DBAs), specifically the loss of coolant accident (LOCA), RB DBA, and as a backup to mitigate the steam line break (SLB) event (Ref. 2). The ESAS relies on the OPERABILITY of the digital actuation logic channels to perform the actuation of the selected systems.

Engineered Safeguards Actuation System Bypasses

No provisions are made for maintenance bypass of ESAS instrumentation channels. Operational bypass of certain channels is necessary to allow accident recovery actions to continue and, for some channels, to allow reactor shutdown without ESAS actuation.

The ESAS RCS pressure analog instrument channels include permissive bistables that allow manual bypass when reactor pressure is below the point at which the low pressure trip is required to be OPERABLE. Once permissive conditions are sensed, the RCS pressure trips may be manually bypassed. Bypasses are automatically removed when bypass permissive conditions are exceeded. Failure of the automatic bypass removal feature or the inability to bypass the RCS pressure function when below 1750 psig does not constitute channel inoperability. However, a channel that remains bypassed when pressure is raised above 1750 psig will be considered inoperable and appropriate conditions will be entered.

This bypass provides an operational provision only outside the Applicability for this Parameter, and provides no safety function. The automatic bypass removal feature is verified during the monthly CHANNEL FUNCTIONAL TEST.

Reactor Coolant System Pressure

The RCS pressure is monitored by three independent pressure transmitters located in the RB. 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 by two bistables to provide a trip signal at $\geq$ 1585 psig and a bypass permissive signal at $\leq$ 1750 psig.

BACKGROUND (continued)

The outputs of the three low RCS pressure trip bistables drive relays in two sets of identical and independent digital instrument channels. These two sets of channels each use two-out-of-three coincidence digital logic for actuation.

Each analog channel can be tested online to verify that the signal and trip setpoint are within the specified allowance requirements of approved calibration procedures. The built-in test facilities permit an electrical trip test of each analog instrument string by the substitution of signals at the buffer amplifiers. When an analog instrument string is placed in test, all associated analog subsystem outputs go to the trip state. This assures that all protective action cannot be defeated by placing analog instrument strings in test.

Reactor Building Pressure

The RB pressure is monitored by three independent pressure transmitters located inside the RB. 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 by two bistables to provide trip signals. The outputs of the bistables, associated with the RB Pressure—High and RB Pressure—High High trips, drive relays in two sets of identical and independent digital instrument channels. These two sets of channels each use two-out-of-three coincidence digital logic for automatic actuation.

Each channel can be tested online to verify that the signal and trip setpoint are within the specified allowance requirements of approved calibration procedures. The built-in test facilities permit an electrical trip test of each analog instrument string by the substitution of signals at the buffer amplifiers. When an analog instrument string is placed in test, all associated analog subsystem outputs go to the trip state. This assures that all protective action cannot be defeated by placing analog instrument strings in test.

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 used in the safety analysis described in SAR, Chapter 14 and Chapter 3A (Ref. 2). The selection of these trip setpoints is such that adequate protection is provided when appropriate sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and environment induced errors, the Allowable Values specified in Table 3.3.5-1 are equal to or conservatively adjusted with respect to the analytical limits. Guidance used to calculate uncertainties associated with the trip setpoints is provided in the Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide,

BACKGROUND (continued)

IDG-001 (Ref. 4). The trip setpoint entered into the bistable may be more conservative than that specified by the Allowable Value to account for changes in instrument error detectable by a CHANNEL FUNCTIONAL TEST. A channel is inoperable if its as-found trip setpoint is not within its required Allowable Value.

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 analyzed.

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

APPLICABLE SAFETY ANALYSES

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

High Pressure Injection

The ESAS actuation of HPI has been assumed for core cooling in the LOCA analysis and is available for boron addition in the SLB analysis.

Low Pressure Injection

The ESAS actuation of LPI has been assumed for large break LOCAs.

Reactor Building Spray, Reactor Building Cooling, and Reactor Building Isolation

The ESAS actuation of the RB coolers and RB Spray have been credited in the RB analysis for LOCAs. Accident dose calculations have credited RB Penetration Room Ventilation, RB Isolation, and RB Spray. The MSLB analysis also credits ESAS actuation of the RB Cooling and RB Spray.

Emergency Power

The ESAS initiated DG Start and ES electrical equipment alignment have been included in the design to ensure that emergency power is available throughout the limiting LOCA scenarios.

The small and large break LOCA analyses (Ref. 2) assume a conservative delay time for the actuation of HPI and LPI. This delay time includes allowances for DG starting, DG loading, Emergency Core Cooling Systems (ECCS) pump starts, and valve alignment. Similarly, the RB Cooling, RB Isolation, and RB Spray have been analyzed with delays appropriate for the entire system analyzed.

APPLICABLE SAFETY ANALYSES (continued)

Accident analyses rely on automatic ESAS actuation for protection of the core temperature and containment pressure limits and for limiting off site dose levels following an accident. These include LOCA, SLB, and other events that result in RCS inventory reduction or severe loss of RCS cooling.

The ESAS instrumentation satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3) for operation in MODE 1. There are no specific safety analyses for operation in MODES 2, 3 and 4. However, industry operating experience has identified the ESAS instrumentation as significant to public health and safety during these operating conditions. Therefore, the ESAS instrumentation satisfies Criterion 4 of 10 CFR 50.36 for operation in MODES 2, 3 and 4.

LCO

The LCO requires three ESAS analog instrument channels for each Parameter in Table 3.3.5-1 to be OPERABLE. Failure of any instrument renders the affected analog instrument channel(s) inoperable and reduces the reliability of the affected Functions.

Only the Allowable Value is specified for each ESAS Function in the LCO. Trip setpoints are provided in the calibration procedures. The 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. Each Allowable Value specified is equal to or more conservative than any analytical limit assumed in the safety analysis to account for instrument uncertainties appropriate to the trip Parameter. Guidance used to calculate the uncertainties associated with the trip setpoints is contained in Instrument Loop Error Analysis Setpoint Methodology, Design Guide, IDG-001 (Ref. 3).

The values for bypass removal functions are stated in the Applicable MODES or Other Specified Condition column of Table 3.3.5-1.

Three ESAS analog instrument channels shall be OPERABLE to ensure that a single failure in one channel will not result in loss of the ability to automatically actuate the required safety systems.

<u>Reactor Coolant System Pressure</u>

Three channels of RCS Pressure - Low are required OPERABLE. Each channel includes a sensor, trip bistable, bypass bistable, bypass relays, and output relays. Failure of a bypass bistable or bypass circuitry, such that an analog instrument channel cannot be bypassed, does not render the channel inoperable since the channel is still capable of performing its safety function, i.e., this is not a safety related bypass function.

LCO (continued)

The trip setpoints are the nominal values at which the bistables are set. For the RCS Pressure—Low, the limiting safety analysis assumes the HPI, LPI, EFIC EFW, ES electrical alignment, and two subsets of RB isolation actuate at ≥ 1520 psig (≥ 1535 psia). The Allowable Value of ≥ 1585 psig includes considerations for instrumentation error and an allowance for margin. Allowances for instrument drift and additional margin are included in the trip setpoint.

Guidance used to calculate the uncertainties associated with the trip setpoints is provided in Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001 (Ref. 4). The explicit uncertainties associated with each setpoint are addressed in the individual design calculations or calibration procedures. Setpoints in accordance with the Allowable Value in conjunction with the LCOs and administrative controls 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 analyzed. An analog instrument channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Reactor Building Pressure

Three channels of RB Pressure—High and RB Pressure—High High are required to be OPERABLE. Each channel includes a pressure switch, bypass relays, and output relays.

The trip setpoints are the nominal values at which the bistables are set. Credit is taken in the safety analyses for RB Pressure—High trip for the actuation of selected systems. The safety analyses for reactor building performance and equipment environmental qualification (pressure and temperature envelope definition) conservatively assume the RB cooling is not initiated until well beyond the expected actual automatic actuation time frame. Therefore, no additional consideration of the instrumentation uncertainties is warranted.

Credit is taken in the safety analyses for RB Pressure—High High trip for the actuation of selected systems. The safety analyses for reactor building performance and equipment environmental qualification (pressure and temperature envelope definition) conservatively assumes the RB spray is not initiated until well beyond the expected actual automatic actuation time frame. Therefore, no additional consideration of the instrumentation uncertainties is warranted.

Therefore, the bistable is considered to be properly adjusted when the "as left" value is consistent with the identified Allowable Value, i.e., for this parameter the trip setpoint and the Allowable Value are the same. Guidance used to calculate the uncertainties associated with the trip setpoints is provided in Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001 (Ref. 4). Setpoints in accordance with the Allowable Value 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 analyzed. An analog instrument channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

APPLICABILITY

Three ESAS analog instrument channels for each of the following Parameters shall be OPERABLE.

1. Reactor Coolant System Pressure - Low Setpoint

The RCS Pressure - Low Setpoint actuation Parameter shall be OPERABLE during operation at or above 1750 psig. This requirement ensures the capability to automatically actuate safety systems and components during conditions indicative of a LOCA or secondary unit overcooling. Below 1750 psig, the low RCS Pressure actuation Parameter can be bypassed to avoid actuation during normal unit cooldowns when safety systems actuations are not required.

The allowance for the bypass is consistent with the transition of the unit to a lower energy state, where there is more margin to safety limits. The unit response to any event, given that the reactor is already tripped, will be less severe and allows more time for operator action to provide manual safety system actuations than in higher energy states. This is even more appropriate during unit heatups when the primary system and core energy content is low, prior to power operation.

In MODES 5 and 6, there is more 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 than in higher MODES. RCS pressure and temperature are very low, and many ES components are administratively controlled or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

2., 3. Reactor Building Pressure - High Setpoint and Reactor Building Pressure - High High Setpoint

The RB Pressure - High and RB Pressure - High High actuation Functions of ESAS shall be OPERABLE in MODES 1, 2, 3, and 4 when the potential for a HELB exists. In MODES 5 and 6, there is more 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 than in higher MODES. Plant pressure and temperature are very low and many ES components are administratively controlled or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

ACTIONS

Required Actions A and B apply to the ESAS 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 an analog instrument channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or ESAS 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 analog instrument channel becomes inoperable in one or more Parameters. If one ESAS analog instrument channel is inoperable, placing it in a tripped condition leaves the system in a one-out-of-two condition for actuation. Thus, if another analog instrument channel were to fail, the ESAS instrumentation could still perform its actuation functions. This action is completed when all of the affected output relays 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, and B.3

Condition B applies when Required Action A.1 and its associated Completion Time are not met, or when one or more parameters have more than one analog instrument channel inoperable. If Condition B applies, 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 within 6 hours. Additionally, for the RCS Pressure—Low parameter, the unit must be brought to < 1750 psig within 36 hours, and for the RB Pressure—High and High High parameters, the unit must be brought 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.

SURVEILLANCE REQUIREMENTS

The ESAS Parameters listed in Table 3.3.5-1 are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

SR 3.3.5.1

Performance of the CHANNEL CHECK every 12 hours provides reasonable assurance for prompt identification of a gross failure of instrumentation. 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 CHANNEL CALIBRATIONs.

Agreement criteria are determined by the unit staff, based on a combination of factors including channel instrument uncertainties. 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 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 potentially more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels.

SR 3.3.5.2

A CHANNEL FUNCTIONAL TEST is performed on each required ESAS analog instrument channel to ensure the entire channel will perform the intended functions. Any setpoint adjustment shall be consistent with the assumptions of the setpoint calculations.

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. The RCS low pressure automatic bypass removal feature is verified during its CHANNEL FUNCTIONAL TEST.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

CHANNEL CALIBRATION is a complete check of the analog 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 analog instrument channel remains OPERABLE between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the setpoint calculations. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint calculations.

This Frequency is justified by the assumption of at least an 18 month calibration interval to determine the magnitude of equipment drift in the setpoint calculations.

REFERENCES

1. SAR, Chapter 7.

2. SAR, Chapter 14 and Chapter 3A.

3. 10 CFR 50.36.

4. Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001.

B 3.3 INSTRUMENTATION

B 3.3.6 Engineered Safeguards Actuation System (ESAS) Manual Initiation

BASES

BACKGROUND

The ESAS manual initiation capability allows the operator to actuate ESAS Functions from the control room in the absence of any other initiation condition. This ESAS manual initiation capability is provided in the event the operator determines that an ESAS Function is needed and has not been automatically actuated. Furthermore, the ESAS manual initiation capability allows operators to rapidly initiate Engineered Safeguards (ES) Functions if the trend of unit parameters indicates that ES actuation will be needed.

LCO 3.3.6 covers only the system level manual initiation of these Functions. LCO 3.3.5, "Engineered Safeguards Actuation System (ESAS) Instrumentation," and LCO 3.3.7, "Engineered Safeguards Actuation System (ESAS) Actuation Logic," provide requirements on the portions of the ESAS that automatically initiate the Functions described earlier.

The ESAS manual initiation Function relies on the OPERABILITY of the digital actuation logic channels (LCO 3.3.7) to perform the actuation of the systems. A manual trip push button is provided on a control room console for each of the digital actuation logic channels. Operation of the push button energizes relays whose contacts perform a logical "OR" function with the automatic actuation.

The ESAS manual initiation channel is defined as the console switch and the instrumentation from the console switch to, but not including, the digital actuation logic channels, which actuate the end devices. Other means of manual initiation, such as controls for individual ES 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.

APPLICABLE SAFETY ANALYSES

The ESAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents, specifically, the loss of coolant accident (LOCA), RB DBA and as a backup to mitigate the steam line break event.

The ESAS manual initiation ensures that the control room operator can rapidly initiate ES Functions. The manual initiation trip Function is required as a backup to automatic trip functions and allows operators to initiate ESAS whenever any parameter is rapidly trending toward its trip setpoint.

APPLICABLE SAFETY ANALYSES (continued)

Operating experience has shown the ESAS manual initiation function to be significant to public health and safety, and therefore satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1).

LCO

Two ESAS manual initiation channels of each ESAS Function shall be OPERABLE whenever conditions exist that could require ES protection of the reactor or RB. Two OPERABLE channels ensure that no single random failure will prevent system level manual initiation of any ESAS Function. The ESAS manual initiation Function allows the operator to initiate protective action prior to automatic initiation or in the event the automatic initiation does not occur.

The ESAS is divided into five Functions actuated by ten manual initiation channels as indicated in the following table:

Function	Associated Channels
High Pressure Injection	1 & 2
Low Pressure Injection	3 & 4
RB Cooling	5 & 6
RB Spray	7 & 8
Spray Additive	9 & 10

The ESAS High Pressure Injection (HPI) Function is actuated by ESAS Manual Initiation channels 1 and 2 and includes the following system actuations: HPI, a subset of reactor building (RB) isolation valves, diesel generators, and ES electrical alignment.

The ESAS Low Pressure Injection (LPI) Function is actuated by ESAS Manual Initiation channels 3 and 4 and includes the following system actuations: LPI, a subset of RB isolation valves, and emergency feedwater (EFW) through an ESAS signal provided to the Emergency Feedwater Isolation and Control (EFIC) System.

The ESAS RB Cooling Function is actuated by ESAS Manual Initiation channels 5 and 6 and includes the following system actuations: RB cooling, a subset of RB isolation valves, and RB penetration room ventilation system.

The ESAS RB Spray Function is actuated by ESAS Manual Initiation channels 7 and 8 and includes the following system actuations: RB spray.

The ESAS Spray Additive Function is actuated by ESAS Manual Initiation channels 9 and 10 and includes the following system actuations: spray additive.

APPLICABILITY

The ESAS manual initiation Functions shall be OPERABLE in MODES 1 and 2, and in MODES 3 and 4 when the associated ES equipment is required to be OPERABLE. The manual initiation channels are required because ES Functions are designed to provide protection in these MODES. ESAS initiates systems that are either reconfigured for decay heat removal operation or disabled while in MODES 5 and 6. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components. Time is available to evaluate unit conditions and to respond by manually operating the ES components, if required.

ACTIONS

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each ESAS manual initiation Function.

A.1

Condition A applies when one manual initiation channel of one or more ESAS 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 of ESAS Function initiation via individual component controls. The 72 hour Completion Time is generally consistent with the allowed outage time for the safety systems actuated by ESAS.

B.1 and B.2

If Required Action A.1 and the associated Completion Time are 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 ESAS manual initiation. This test verifies that the initiating circuitry is OPERABLE and will actuate the digital actuation logic channels. The 18 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 18 month Frequency.

REFERENCES

1. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.7 Engineered Safeguards Actuation System (ESAS) Actuation Logic

BASES

BACKGROUND

The digital actuation logic channels of ESAS are defined as the instrumentation between, but not including, the buffers of the analog instrument channels and the unit controls that actuate ESAS equipment. Each of the components actuated by the ESAS Functions is associated with one or more digital actuation logic channels. If two-out-of-three ESAS analog instrument channels indicate a trip, or if channel level manual initiation occurs, the digital actuation logic channel is activated and the associated equipment is actuated.

The purpose of requiring OPERABILITY of the ESAS digital actuation logic channels is to ensure that the Functions of the ESAS 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 digital actuation logic channels alone will not ensure that each Function can be activated; the analog instrument channels and actuated equipment associated with each Function must also be OPERABLE to ensure that the Functions can be automatically initiated during an accident.

LCO 3.3.7 covers only the digital actuation logic channels that initiate these Functions. LCO 3.3.5, "Engineered Safeguards Actuation System (ESAS) Instrumentation," and LCO 3.3.6, "Engineered Safeguards Actuation System (ESAS) Manual Initiation," provide requirements on the analog instrument and manual initiation channels that input to the digital actuation logic channels.

The ESAS, in conjunction with the actuated equipment, provides protective functions necessary to mitigate Design Basis Accidents (DBAs), specifically, the loss of coolant accident (LOCA) and steam line break (SLB) events. The ESAS relies on the OPERABILITY of the digital 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 BAW-10192PA (Ref. 2). This delay time includes allowances for diesel generator (DG) starts, DG loading, ECCS pump starts, and valve alignment. Similarly, the reactor building (RB) Cooling, RB Isolation, and RB Spray have been analyzed with delays appropriate for the entire system.

BACKGROUND (continued)

The ESAS automatic initiation of Engineered Safeguards (ES) 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, RB Cooling, RB Spray, RB Spray Additive, and RB Isolation.

APPLICABLE SAFETY ANALYSES

Accident analyses rely on automatic ESAS actuation for protection of the core and RB and for limiting off site dose levels following an accident. The digital actuation logic is an integral part of the ESAS.

The ESAS actuation logic satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3) for operation in MODE 1. There are no specific safety analyses for operation in MODES 2, 3 and 4. However, industry operating experience has identified the ESAS actuation logic as significant to public health and safety during these operating conditions. Therefore, the ESAS actuation logic satisfies Criterion 4 of 10 CFR 50.36 for operation in MODES 2, 3 and 4.

LCO

The digital actuation logic channels are required to be OPERABLE whenever conditions exist that could require ES protection of the reactor or the RB. This ensures automatic initiation of the ES required to mitigate the consequences of accidents.

The ESAS is divided into five Functions actuated by ten digital actuation logic channels as indicated in the following table:

Function	Associated Channels
High Pressure Injection	1 & 2
Low Pressure Injection	3 & 4
RB Cooling	5 & 6
RB Spray	7 & 8
Spray Additive	9 & 10

The ESAS HPI Function is actuated by ESAS digital actuation logic channels 1 and 2 and includes the following system actuations: HPI, a subset of RB isolation valves, DGs, and ES electrical alignment. Digital actuation logic channels 1 and 2 are actuated by two-out-of-three RCS Pressure—Low analog instrument channels, or two-out-of-three RB Pressure—High analog instrument channels.

LCO (continued)

The ESAS LPI Function is actuated by ESAS digital actuation logic channels 3 and 4 and includes the following system actuations: LPI, a subset of RB isolation valves, and EFW through an ESAS signal provided to EFIC. Digital actuation logic channels 3 and 4 are actuated by two-out-of-three RCS Pressure—Low analog instrument channels, or two-out-of-three RB Pressure—High analog instrument channels.

The ESAS RB Isolation and Cooling Function is actuated by ESAS digital actuation logic channels 5 and 6 and includes the following system actuations: RB cooling, a subset of RB isolation valves, and RB penetration room ventilation system. Digital actuation logic channels 5 and 6 are actuated by two-out-of-three RB Pressure—High analog instrument channels.

The ESAS RB Spray Function is actuated by ESAS digital actuation logic channels 7 and 8 and includes the following system actuations: RB spray. Digital actuation logic channels 7 and 8 are actuated by two-out-of-three RB Pressure—High High analog instrument channels.

The ESAS Spray Additive Function is actuated by ESAS digital actuation logic channels 9 and 10 and includes the following system actuations: spray additive. Digital actuation logic channels 9 and 10 are actuated by two-out-of-three RB Pressure—High High analog instrument channels.

APPLICABILITY

The digital actuation logic channels shall be OPERABLE in MODES 1 and 2, and in MODES 3 and 4 when the associated ES equipment is required to be OPERABLE, because ES 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 ESAS are either reconfigured for decay heat removal operation or disabled. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components. Time is available to evaluate unit conditions and respond by manually operating the ES components, if required.

ACTIONS

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each ESAS digital actuation logic channel.

ACTIONS (continued)

A.1 and A.2

When one or more digital actuation logic channel(s) are inoperable, the associated component(s) can be placed in their ES configuration. Required Action A.1 is equivalent to the digital actuation logic channel performing its safety function ahead of time. In some cases, placing the component in its ES 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 ES configuration include, but are not limited to, violation of system separation, activation of fluid systems that could lead to thermal shock, isolation of fluid systems that are normally functioning, and actuation of components which would not return to their actuated condition upon restoration of electrical power. 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.2 requires entry into the Required Actions of the affected supported systems, since the true effect of digital actuation logic channel 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. A combination of Required Actions A.1 and A.2 may be used for different components associated with an inoperable ESAS digital actuation logic channel.

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1

SR 3.3.7.1 is the performance of a CHANNEL FUNCTIONAL TEST on a 31 day Frequency. The test demonstrates that each digital actuation logic channel successfully performs the two-out-of-three logic combinations every 31 days. The test simulates the required one-out-of-three inputs to the logic circuit and verifies the successful operation of the digital 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. The CHANNEL FUNCTIONAL TEST performed for the Reactor Building Spray System Logic Channels shall include testing of the associated spray pump, spray valves, and chemical additive valve logic channels.

REFERENCES

1. 10 CFR 50.46.

2. BAW-10192PA, “BWNT Loss-of-Coolant Accident Evaluation Model for OTSG Plants, Volumes I and II,” June 1998.

3. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.8 Diesel Generator (DG) Loss of Power Start (LOPS)

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow operation of safety related loads. Undervoltage protection will generate a LOPS in the event a loss of voltage or degraded voltage condition occurs on unit vital buses. There are two LOPS Functions for each 4.16 kV vital bus.

Two undervoltage relays with inverse voltage time characteristics are provided on each 4.16 kV Class 1E bus for the purpose of detecting a loss of bus voltage. The relay Allowable Values are based on a maximum setting, which is below the lowest allowed motor terminal momentary voltage of 75% of motor voltage rating of 4000 V. The Allowable Values are adjusted to include channel uncertainties and calibration tolerances. Upon loss of power to either of these relays, in approximately 1.0 second, load shedding and starting of the associated DG are initiated. Isolation of the safety related buses is delayed approximately 2.0 seconds to allow an automatic transfer to offsite power. The safety related bus is isolated only if the transfer is unsuccessful.

Two definite time undervoltage relays are provided on each safety related 480 V load center bus with a coincident trip logic (2 out of 2) for the purpose of detecting a sustained undervoltage condition. The undervoltage relay Allowable Values on the 480 V bus are based on long term motor voltage requirements plus the maximum feeder voltage drop allowance resulting in a nominal setting of 92% of the motor rated voltage of 460 V. The Allowable Values are adjusted to include channel uncertainties and calibration tolerances. Upon voltage degradation to 92% of 460 V and after a delay of 8 seconds, both relays must operate to isolate the associated safety related 4.16 kV bus from offsite power, and start and connect the associated DG. The relays are delayed 8.0 seconds to prevent spurious operation of the relays when large motors start on the safety related 4.16 kV and 480 V buses. The LOPS is further described in SAR, Section 8.3.1 (Ref. 1).

Trip Setpoints

The Allowable Values associated with the relays are consistent with the analytical limits presented in SAR, Section 8.3.1 (Ref. 1). The selection of these values is such that adequate protection is provided when all sensor and processing time delays are taken into account. A channel is inoperable if its actuation trip setpoint is not within its required Allowable Value.

BACKGROUND (continued)

A complete loss of offsite power will result in approximately a 1 second delay in LOPS actuation. The DG starts and is available to accept loads within a 15 second time interval on actuation by the Engineered Safeguards Actuation System (ESAS) or LOPS. Emergency power is established within the maximum time delay assumed for each event analyzed in the accident analysis in which a loss of offsite power is assumed (Ref. 2).

The DG LOPS protection channels conform to the single failure criteria of IEEE-279-1971 as discussed in Ref. 1.

APPLICABLE SAFETY ANALYSES

The DG LOPS is required for the Engineered Safeguards (ES) to function in any accident which assumes a loss of offsite power.

Accident analyses credit the loading of the DG, based on the loss of offsite power, during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESAS actuation. The diesel loading has been included in the assumed delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analysis assumes a nonmechanistic DG loading, which does not explicitly account for each individual component of the loss of power detection and subsequent actions. The total assumed actuation time for the limiting systems, high pressure injection, and low pressure injection includes contributions from the DG Start, DG loading, and safety injection system component actuation. The response of the DG 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 ES systems powered from the DGs, provide unit protection for the analyzed accidents in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ES equipment include the 15 second DG start delay and, if applicable, the appropriate sequencing delay. The assumed response times for ESAS actuated equipment in LCO 3.3.5, "Engineered Safeguards Actuation System (ESAS) Instrumentation," include the appropriate DG loading and sequencing delay.

In MODE 1, the DG LOPS channels satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3). There are no specific safety analyses for operation in MODES 2, 3, and 4. However, industry operating experience has identified DG LOPS as significant to public health and safety during these operating conditions. Therefore, in MODES 2, 3 and 4, the DG LOPS channels satisfy Criterion 4 of 10 CFR 50.36.

LCO

The LCO for the DG LOPS requires that two relays per DG (DG1 and DG2) of the loss of voltage instrumentation Function shall be OPERABLE and two relays per DG of the degraded voltage instrumentation Function shall be OPERABLE to ensure that the automatic 4.16 kV bus isolation capability and automatic start of the DG is available when needed. The degraded voltage relays may be bypassed for ≤ 30 seconds during reactor coolant pump start to prevent such starts from initiating spurious DG LOPS, separation of the ES busses from offsite power, and subsequent loading of the DG. Therefore, the automatic bypass and associated alarms are required functions for OPERABILITY of the DG LOPS instrumentation.

Loss of either DG LOPS function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents.

The Allowable Values must be met for each Function to be considered OPERABLE. Allowable Values are specified in the specifications. The 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. Each Allowable Value is more conservative than any analytical limit assumed in the transient and accident analysis and the trip setpoint is equal to or more conservative to the Allowable Value, accounting for instrument uncertainties appropriate to the trip function. Guidance used to calculate the uncertainties associated with the relay settings is contained in the ANO-1 Design Guide, IDG-001, "Instrument Loop Error Analysis and Setpoint Methodology Manual" (Ref. 4).

The LOPS relay Allowable Values are based on the short term starting voltage protection as well as long term running voltage protection. The 4.16 kV undervoltage relay Allowable Values are based on a maximum setting, which is below the lowest allowed motor terminal momentary voltage of 75% of motor rated voltage of 4000 V. The 480 V undervoltage relay Allowable Values are based on long term motor voltage requirements plus the maximum feeder voltage drop allowance resulting in a nominal 92% setting of the motor rated voltage of 460 V. The Allowable Values for both the 4.16 kV and the 480 V relays include adjustments for channel uncertainties and calibration tolerances.

APPLICABILITY

The DG LOPS actuation Function shall be OPERABLE in MODES 1, 2, 3, and 4 because ES Functions are required to be OPERABLE in these MODES. Automatic actuation is not required in MODES 5 or 6 since there is no automatic protective function on a loss of power or degraded power to the vital bus.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function.

If a relay's trip setpoint is found nonconservative with respect to the Allowable Value, or the relay is found inoperable, then the function that the relay provides must be declared inoperable and the LCO Condition entered for the particular protection function affected. Since the required relay Functions are specified on a per DG basis, the Condition may be entered separately for each DG.

A.1

With one or more relays in one or more Functions for one or more DGs inoperable, Required Action A.1 requires the inoperable relay(s) to be restored to OPERABLE status within 1 hour. With a relay of a Function inoperable, the logic is not capable of providing an automatic DG LOPS signal for valid conditions for the associated DG. 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 LOPS occurring during this interval.

B.1

Condition B applies if the Required Action and associated Completion Time of Condition A are not met.

Required Action B.1 ensures that Required Actions for affected diesel generator inoperabilities are initiated. Depending on the DG(s) affected, the appropriate Actions specified in LCO 3.8.1, "AC Sources - Operating," are required immediately.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 7 days provides reasonable assurance for prompt identification of a gross failure of instrumentation. CHANNEL CHECK will detect gross channel failure; therefore, it is key in verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

The Frequency is based on operating experience that demonstrates channel failure is rare. Since the probability of random failure in any 7 day period is low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of this instrumentation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2

The Note allows channel bypass for testing of the loss of voltage Function without entering the associated Conditions and Required Actions, although during this time period it cannot actuate a diesel start. This allowance is based on the assumption that 4 hours is the average time required to perform channel Surveillance. The 4 hour testing allowance does not significantly reduce the probability that the DG will start when necessary. It is not acceptable to remove channels from service for more than 4 hours to perform required Surveillance testing without declaring the channel inoperable.

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 verify that setpoints are within the required ranges.

The Frequency is based on the reliability of the components, on operating experience which demonstrates channel failure is rare, and on consistency with the typical industry refueling cycle, and is justified by the assumption of at least an 18 month calibration interval in the determination of equipment drift.

REFERENCES

1. SAR, Section 8.3.1.

2. SAR, Chapter 6 and 14.

3. 10 CFR 50.36.

4. ANO-1 Design Guide, IDG-001, "Instrument Loop Error Analysis and Setpoint Methodology Manual."

B 3.3 INSTRUMENTATION

B 3.3.9 Source Range Neutron Flux

BASES

BACKGROUND

The source range neutron flux channels provide the operator with an indication of the approach to criticality. These channels also provide the operator with a flux indication that reveals changes in reactivity.

The source range instrumentation has two redundant count rate channels originating in two high sensitivity fission chambers. Two source range detectors are externally located on opposite sides of the core. These channels are used over a counting range of 0.1 cps to 1E5 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 -1 decades to +7 decades per minute. An interlock provides a control rod withdraw "inhibit" on a high startup rate of +2 decades per minute in either channel. This interlock is bypassed when the intermediate range neutron flux channels reach 1E-9 amps or power range neutron flux channels reach 10% RTP.

APPLICABLE SAFETY ANALYSES

The source range neutron flux channels are necessary to monitor core reactivity changes. They are the primary means for detecting reactivity changes 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. They also trigger operator actions to anticipate RPS actuation in the event of reactivity transients starting from shutdown or low power conditions.

The source range neutron flux channels satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1).

LCO

One source range neutron flux channel shall be OPERABLE to provide the operator with source range neutron instrumentation. The source range instrumentation provides the primary power indication at ≤ 1E-10 amp on intermediate range instrumentation and must remain OPERABLE for the operator to continue increasing power.

APPLICABILITY

One source range neutron flux channel shall be OPERABLE in MODE 2 to provide 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 neutron flux 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, A.2, A.3, and A.4

With the required source range neutron flux channel inoperable with ≤ 1E-10 amp on the intermediate range neutron flux instrumentation, the operators must take actions to limit the possibilities for adding positive reactivity. This is done by immediately suspending positive reactivity additions, initiating action to insert all CONTROL RODS, and opening the control rod drive trip breakers within 1 hour. RCS temperature changes are permitted, however, provided the effects of such temperature changes are accounted for in the SDM calculations. 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 these MODES, 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 A.1, Required Action A.2, and Required Action A.3 preclude rapid positive reactivity additions. The 1 hour Completion Time for Required Action A.3 and Required Action A.4 provides sufficient time for operators to accomplish the actions. The 12 hour Frequency for performing the SDM verification provides reasonable assurance that the reactivity changes possible with CONTROL RODS inserted are detected before SDM limits are challenged.

If no indication of intermediate range flux is available, these Required Actions are also appropriate.

ACTIONS (continued)

B.1

With > 1E-10 amp in MODE 2, 3, 4, or 5 on the intermediate range neutron flux instrumentation, continued operation is allowed with the required source range neutron flux channel 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 required channel to OPERABLE status for future availability. The Completion Time of 1 hour is sufficient to initiate the action. The action must continue until the channel is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1

Performance of the CHANNEL CHECK once every 12 hours provides reasonable assurance of prompt identification of a gross failure of instrumentation. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to the same 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 factors including channel instrument uncertainties. If a channel is outside the criteria, it may be an indication that 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.

The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. For example, during a power reduction near the bottom of the scale for the intermediate range monitors, a source range monitor reading is expected with at least one decade overlap. Without such an overlap, the source range monitors are considered inoperable unless it is clear that an intermediate range monitor inoperability is responsible for the lack of the expected overlap.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.1 (continued)

The Frequency 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 channel. When operating with only one channel OPERABLE, CHANNEL CHECK is still required. However, in this condition, a redundant source range may not be available for comparison. CHANNEL CHECK may still be performed via comparison with intermediate range detectors, if available, and verification that the OPERABLE source range channel is energized and indicating a value consistent with current unit status.

SR 3.3.9.2

For a source range neutron flux channel, CHANNEL CALIBRATION is a complete check and readjustment of the channel from the preamplifier input to the indicator. This test verifies the channel responds to measured parameters within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel at a setpoint which accounts 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, and 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. Finally, the detectors are of simple construction, and any failures in the detectors will be apparent as 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

1. 10 CFR 50.36.

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 channels originating in two 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 while below 10% RTP.

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 provide the primary indication to trigger operator actions to anticipate Reactor Protection System actuation in the event of reactivity transients starting from low power conditions.

The intermediate range neutron flux channels satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1).

LCO

One intermediate range neutron flux instrumentation channel shall be OPERABLE to provide the operator with neutron flux indication. This enables 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.

APPLICABILITY

The required intermediate range neutron flux channel 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 when the power range and source range instrumentation cannot provide reliable indications, e.g., during initial criticality and power escalation. Since those conditions can exist in, or propagate from, all of these MODES, the intermediate range instrumentation must be OPERABLE.

ACTIONS

A.1 and A.2

With the required intermediate range neutron flux channel inoperable when THERMAL POWER is ≤ 5% RTP, 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. RCS temperature changes are permitted provided the effects of such changes are accounted for in the SDM caculations. 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.10.1

Performance of the CHANNEL CHECK once every 12 hours provides reasonable assurance of prompt identification that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to the same 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.10.1 (continued)

Agreement criteria are determined by the unit staff based on a combination of factors including channel instrument uncertainties. If a channel is outside the criteria, it may be an indication that 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. Off scale low current loop channels are verified, where practical to be reading at the bottom of the range and not failed low.

The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. For example, during a power increase near the top of the scale for the source range monitors, an intermediate range monitor reading is expected with at least one decade overlap. Without such an overlap, the intermediate range monitors are considered inoperable unless it is clear that a source range monitor inoperability is responsible for the lack of the expected overlap. Further, during a power reduction near the bottom of the scale for the power range monitors, an intermediate range monitor reading is expected with at least one decade overlap. Without such an overlap, the intermediate range monitors are considered inoperable unless it is clear that a power range monitor inoperability is responsible for the lack of the expected overlap.

The Frequency, about once every shift, 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 channel.

When operating with only one channel OPERABLE, 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.

SR 3.3.10.2

A CHANNEL FUNCTIONAL TEST, of the required intermediate range instrument channel, verifies proper operation of the channel each 31 days. Monthly testing provides reasonable assurance that the instrument channel will function, if required, to provide indication during MODE 2 and during unanticipated reactivity excursions from MODES 3, 4, or 5.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.10.3

For intermediate 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 a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel at a setpoint which accounts 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

1. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.11 Emergency Feedwater Initiation and Control (EFIC) Instrumentation

BASES

BACKGROUND

The EFIC System instrumentation is designed to protect against the consequences of a simultaneous blowdown of both steam generators. Steam generator (SG) isolation is actuated to protect the core during an overcooling condition upon a main steam or feedwater line rupture. The Emergency Feedwater (EFW) System is actuated to protect the core during an overheating condition upon a loss of main feedwater or a loss of primary side forced circulation (loss of all four reactor coolant pumps). In addition, EFIC controls the EFW flow rate to the SG(s) to control SG level and minimize overcooling. EFIC also selects the appropriate SG(s) under conditions of steam line break or main feedwater or emergency feedwater line break downstream of the last check valve, and provides for isolation of the main steam and main feedwater lines of a depressurized steam generator. The EFIC Functions that are supported and the parameters that are needed for each of these Functions are described next.

The EFIC instrumentation contains devices and circuitry that generate the following signals when monitored variables reach levels that are indicative of conditions requiring protective actions.

a. EFW Initiation;

b. EFW Vector Valve Control; and

c. Main Steam Line Isolation.

EFW is initiated to restore a source of cooling water to the secondary system when conditions indicate that the normal source of feedwater is insufficient to continue heat removal. The two indications used for this are the loss of both MFW pumps and a low level in the steam generator (SG). Also, EFW is initiated when action is being taken to isolate the MFW from the SG during conditions of uncontrolled depressurizations. This is done by initiating EFW when steam pressure reaches the low SG pressure setpoint. Also, EFW is initiated when the primary system experiences a total loss of forced circulation. This initiation, on the loss of all reactor coolant pumps (RCPs), ensures the EFW is available to raise SG levels to promote natural circulation cooling.

The EFIC System initiates EFW when an Engineered Safeguards Actuation System (ESAS) signal is initiated on low RCS pressure or high reactor building pressure (ESAS Channels 3 and 4) in order to support heat removal following Emergency Core Cooling System (ECCS) actuation. This is a digital signal provided by the

BACKGROUND (continued)

ESAS Automatic Actuation Logic. Refer to the Bases for LCO 3.3.5, “Engineered Safeguards Actuation System (ESAS) Instrumentation,” and LCO 3.3.7, “Engineered Safeguards Actuation System (ESAS) Automatic Actuation Logic,” for additional discussion.

The EFIC System also initiates EFW on loss of main feedwater flow as part of the Diverse Reactor Overpressure Protection System (DROPS) which is the system provided for ANO-1 to comply with requirements to reduce risk from an anticipated transient without scram (ATWS). The DROPS consists of the Diverse Scram System (DSS) and the ATWS Mitigation System Actuation Circuitry (AMSAC). EFW initiation for ATWS prevention and mitigation is not required by this Specification.

The EFIC System also isolates main steam and MFW to an SG that has experienced an uncontrolled depressurization. With the uncontrolled depressurization, the heat sink temperature control is lost and the heat removal rate cannot be controlled. The main steam and MFW are isolated to an SG when the steam pressure reaches a low setpoint below the normal operating point of the secondary system.

EFW initiation also enables EFIC vector logic which performs an EFW control function to preclude the delivery of fluid to a depressurized SG, thereby avoiding an uncontrolled cooling condition as long as the other SG remains pressurized. When both of the SGs are depressurized, the EFIC vector logic provides EFW flow to both SGs until a significant pressure difference between the two SGs is developed, thereby ensuring that core cooling is maintained.

Trip Setpoints and Allowable Values

The trip setpoints are the 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 SAR, Chapters 7 and 14 (Refs. 2 and 3). The selection of these trip setpoints is such that adequate protection is provided when appropriate sensor and processing time delays are taken into account.

For all EFIC functions except the SG Level – Low function, the Allowable Values are Limiting Safety System Settings (LSSS) required by 10 CFR 50.36 and are conservatively adjusted with respect to the analytical limits to allow for calibration tolerances, instrumentation uncertainties, instrument drift, and environmental errors as required.

For the SG Level – Low function, the “limiting trip setpoint” is the LSSS required by 10 CFR 50.36 and includes additional uncertainties such as drift, calibration uncertainty, and uncertainties determined during normal operation. The Limiting Trip Setpoint also provides a means to identify unacceptable instrument performance that may require corrective action.

BACKGROUND (continued)

Guidance used to calculate the uncertainties associated with the Allowable Values and, the Limiting Trip Setpoint for the SG Level – Low function, is provided in Instrument Loop Error Analysis and Setpoint Methodology Manual Design Guide, IDG-001 (Ref. 4). The methodology incorporated is consistent with Method 3 of ISA-RP67.04.02-2000, *Methodologies for the Determination of Setpoints for Nuclear Safety Related Instrumentation*. The explicit uncertainties are addressed in the design calculations as required. The trip setpoint entered into the bistable may be more conservative than that specified by the Allowable Value to account for changes in instrument error detectable by a CHANNEL FUNCTIONAL TEST. A channel is inoperable if its as-found trip setpoint is not within its required Allowable Value.

Setpoints in accordance with the Allowable Value in conjunction with the LCOs and administrative controls 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 analyzed.

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

Actuation Logic

SAR, Section 7.1.4 (Ref. 2), describes the EFIC EFW Initiation logic operation.

Each EFIC train actuates on a one-out-of-two taken twice combination of trip signals from the instrumentation channels. Each EFIC channel can issue an initiate command, but an EFIC actuation will take place only if at least two channels issue initiate commands. For the EFW Initiation and Main Steam Line Isolation functions, the one-out-of-two taken twice logic combinations are transposed between trains so that failure of two channels prevents actuation of, at most, one train.

More detailed descriptions of the EFIC instrumentation are provided below.

1. EFW Initiation

Figure 10-2, SAR, Chapter 10 (Ref. 5), illustrates each channel of the EFIC EFW Initiation Function. The individual instrumentation channels that serve EFIC EFW Initiation Function are discussed next.

a. Loss of MFW Pumps (Control Oil Pressure)

Loss of both MFW Pumps is one of the six parameters within the EFIC System that automatically initiates EFW. The MFW Pump status instrumentation, and associated bypasses, are internal to the Reactor Protection System (RPS). For RPS, loss of MFW Pumps is detected by MFW Pump turbine control oil pressure. Each RPS channel receives MFW Pump status information from one of four pressure switches per pump. If both switches in a single channel trip (one from each pump), the associated RPS channel trips. Each RPS channel provides a

BACKGROUND (continued)

contact input into its associated EFIC channel representative of both MFW Pumps tripped. At least two EFIC channels in trip are required for EFW Initiation. This Function is automatically bypassed when THERMAL POWER is < 10% RTP and the bypass is automatically removed when THERMAL POWER is ≥ 10% RTP. The bypass functions occur internal to the RPS, i.e., prior to input to the EFIC System. This parameter value (i.e., 10% RTP) is a nominal value consistent with the requirements of LCO 3.3.1, "RPS Instrumentation."

Loss of both MFW Pumps was chosen as an EFW automatic initiating parameter because it is a direct and immediate indicator of loss of MFW.

b. SG Level – Low

Four EFIC dedicated low range level transmitters per SG are used to generate the signals used for detection for low level conditions for EFW actuation. There is one transmitter for each of the four channels A, B, C, and D. At least two channels are required to initiate EFW. SG Level - Low was chosen as an EFW automatic initiating parameter because it indicates that the normal feedwater source may be insufficient to meet the heat removal requirements.

Signals from channels A and B are also used to control SG level at approximately 31 inches when one or more RCPs are operating. This parameter is referenced to the top of the lower tube sheet.

c. SG Pressure – Low

Four transmitters per SG (one transmitter per channel) provide the EFIC System with channels A through D of SG Pressure - Low. These are the same transmitters used by the Main Steam Line Isolation Function. When the SG pressure at the transmitter drops below the bistable Allowable Value of 584.2 psig on a given channel, an EFW Initiation signal is sent to the automatic actuation logic. At least two channels are required to initiate EFW and main steam line isolation. The Allowable Value of ≥ 584.2 psig includes consideration for instrumentation error and an allowance for margin. Allowances for instrument drift and additional margin are included in the trip setpoint. The low pressure Function may be manually bypassed when either SG is less than 750 psig. If both SG pressure inputs exceed 750 psig, the EFIC channel bypass is automatically removed. The low pressure operational bypass allows for normal cooldown without EFIC actuation. The parameter value (i.e., 750 psig) is a nominal value. Should the channel remain bypassed above 750 psig, the channel is considered inoperable and appropriate conditions are entered. Failure of the automatic bypass removal feature alone or the inability to bypass a channel when below 750 psig does not constitute channel inoperability. The automatic bypass removal feature is verified during the monthly CHANNEL FUNCTIONAL TEST.

BACKGROUND (continued)

SG Pressure - Low is a primary indication and actuation signal for a steam line break or feedwater line break (non-design basis transient). For a small break, which does not depressurize the SG or takes a long time to depressurize the SG, automatic actuation is not required. The operator has time to diagnose the problem and take the appropriate actions.

d. RCP Status

A loss of power to all four RCPs is an indication of a pending loss of forced flow in the Reactor Coolant System. These signals are input into the four channels of EFIC.

When at least two channels issue initiate commands based on loss of all RCPs, the EFIC System will automatically actuate EFW and control the level at approximately 312 inches in the SG. This higher level provides a thermal center in the SG at a higher elevation than that of the reactor to enhance natural circulation of the reactor coolant. This parameter is referenced to the top of the lower tube sheet.

To allow heatup and cooldown operations without actuation, a bypass permissive of 10% RTP is used. The 10% bypass permissive was chosen because it was an available, qualified Class 1E signal at the time the EFIC System was designed. When the first RCP is started, the "loss of four RCPs" initiation signal may be manually reset. If the bypass is not manually reset, it will be automatically reset when the unit reaches 10% power. Should the channel remain bypassed when ≥ 10% RTP, the channel is considered inoperable and appropriate conditions are entered. Failure of the automatic bypass removal feature alone or the inability to bypass a channel when below 10% RTP does not constitute channel inoperability. The automatic bypass removal feature is verified during the monthly CHANNEL FUNCTIONAL TEST.

During cooldown, the bypass may be inserted at any time the power has been reduced below 10% RTP. However, for most operating conditions, this trip function remains active until after the Decay Heat Removal System has been initiated and the system is ready for the last RCP to be tripped. This trip function must be bypassed prior to stopping the last RCP. This parameter value (i.e., 10% RTP) is a nominal value consistent with the requirements of LCO 3.3.1, “RPS Instrumentation.”

e. ESAS

The EFIC System initiates EFW when an ESAS signal is initiated on low RCS pressure or high reactor building pressure (ESAS Channels 3 and 4) in order to support heat removal following ECCS actuation. This is a digital signal provided by the ESAS Automatic Actuation Logic. Refer to the Bases for LCO 3.3.5, “Engineered Safeguards Actuation System (ESAS) Instrumentation,” and LCO 3.3.7, “Engineered Safeguards Actuation System (ESAS) Automatic Actuation Logic,” for additional discussion.

BACKGROUND (continued)

f. DROPS

The EFIC System also initiates EFW on loss of main feedwater flow as part of the DROPS which is the system provided for ANO-1 to comply with requirements to reduce risk from an ATWS. The DROPS consists of the Diverse Scram System (DSS) and the ATWS Mitigation System Actuation Circuitry (AMSAC) . EFW initiation for ATWS prevention and mitigation is not required by this Specification.

2. EFW Vector Valve Control

Figure 10-2, SAR, Chapter 10 (Ref. 5), illustrates the EFIC EFW Vector Valve Control inputs to the EFIC Vector Logic (See Bases for LCO 3.3.14, "EFIC Vector Logic"). The function of the EFW vector logic is to determine whether EFW should not be fed to one or the other SG once enabled by the EFW Initiation Function. This is to preclude the continued addition of EFW to a depressurized SG and, thus, to minimize the overcooling effects.

Each set of vector logic receives SG pressure information from bistables located in the input logic of the same EFIC channel. The pressure information received is:

a. SG A pressure less than 584.2 psig;

b. SG B pressure less than 584.2 psig;

c. SG A pressure 100 psid greater than SG B pressure; and

d. SG B pressure 100 psid greater than SG A pressure.

The Allowable Value of ≥ 584.2 psig includes consideration for instrumentation error and an allowance for margin. Allowances for instrument drift and additional margin are included in the trip setpoint. The 100 psid value is considered to be a nominal value.

The vector logic outputs are in a neutral state until enabled by the train A or B trip logics. When enabled, the vector logic can issue close commands to the EFW control valves and open or closed commands to the EFW isolation valves per the selected channel assignments. The level control module provides input to the flow controllers which control the position of the EFW control valves.

Each vector logic may isolate EFW to one SG or the other, never both.

The valve open or close commands are determined by the relative values of SG pressures as discussed in the Bases for LCO 3.3.14.

BACKGROUND (continued)

3. Main Steam Line Isolation

SAR, Section 7.1.4 (Ref. 2) describes one channel of the EFIC Main Steam Line Isolation logic. Four pressure transmitters (one transmitter per channel) per SG provide EFIC with channels A through D logic of SG pressure. The channels are as described for EFW Initiation mentioned earlier.

Bypass

One of the four initiation channels can be put into "maintenance bypass." Bypassing one initiation channel isolates that channel's signal to the functions fed from initiation channel but does not bypass the trip logic within the actuation train. An interlock feature prevents bypassing more than one channel at a time. In addition, since the EFIC System receives signals from the RPS, the maintenance bypass from the RPS is interlocked with the EFIC System. If one channel of the RPS is in maintenance bypass, only the corresponding channel of the EFIC may be bypassed (e.g., channel A, RPS, and channel A, EFIC). This ensures that only the corresponding channels of the EFIC and RPS are placed in maintenance bypass at the same time.

EFIC channel maintenance bypass does not bypass EFW Initiation from ESAS. The EFIC EFW initiation from ESAS is, however, bypassed when its associated ESAS channel is bypassed.

The operational bypass provisions were discussed as part of the individual Functions described earlier.

The EFIC System is designed to perform its intended EFW Initiation and Main Steam Line Isolation function with one channel in maintenance bypass (in effect, inoperable) concurrent with a postulated single failure in any one of the remaining channels. This is in compliance with IEEE-279-1971 (Ref. 6).

APPLICABLE SAFETY ANALYSES

1. EFW Initiation

Although loss of both MFW pumps is a direct and immediate indicator of loss of MFW, other scenarios such as valve closures could potentially cause loss of feedwater. As part of the post-TMI review, a loss of main feedwater was analyzed (Ref. 3). The EFIC System response for a loss of MFW conservatively assumes the actuation of EFW on low SG level. If the loss of feedwater is due to loss of MFW pumps, EFW will be actuated earlier than it would on low SG level, which will increase the SG heat transfer capability and will lessen the severity of the transient.

The basis for initiation of the EFW systems is a loss of MFW. For this analysis, SG Level - Low is the most conservative parameter from which to automatically initiate EFW since this yields the least SG inventory available for heat removal. SG Level - Low would be an indicator of any event involving a loss of SG secondary side inventory heat removal capability.

APPLICABLE SAFETY ANALYSES (continued)

SG Pressure - Low is a primary indication and provides an actuation signal for a SLB. In the SLB analyses, SAR Section 14.2.2.1 (Ref. 3), EFIC initiation occurs; however, no EFW flow occurred because level did not reach the SG Level - Low setpoint.

Loss of four RCPs is a primary indicator of the need for emergency feedwater (EFW) for the loss of electric power analysis, SAR Section 14.1.2.8 (Ref. 3).

The SAR SBLOCA analyses, SAR Section 14.2.2.5 (Ref. 3), assume initiation of EFW based on concurrent loss of offsite power and the resultant loss of four RCPs. Initiation of EFW would also occur when an ESAS signal is generated on low RCS pressure or high reactor building pressure (ESAS Channels 3 or 4) in order to support heat removal following ECCS actuation, however, these are considered backup initiation responses.

2. EFW Vector Valve Control

The SAR SLB analyses, SAR Section 14.2.2.1 (Ref. 3), consider isolation of the affected SG as a function automatically performed by the EFIC System. The EFIC Vector Logic utilizes the EFW Vector Valve Control Functions (i.e., SG Pressure - Low and SG Differential Pressure - High) to determine which steam generator is associated with the rupture and provide appropriate isolation.

3. Main Steam Line Isolation

The SAR SLB analyses, SAR Section 14.2.2.1 (Ref. 3), assume actuation of the Main Steam Line Isolation on SG Pressure - Low, initiating closure of the main steam isolation valves and the main feedwater isolation valves. The steam generator in the steam loop associated with the rupture blows dry after feedwater isolation. EFW flow is available to the unaffected steam generator to preserve the availability of an RCS heat sink.

In MODE 1, the EFIC System satisfies Criterion 3 of 10 CFR 50.36 (Ref. 7). In MODES 2 and 3, the EFIC System satisfies Criterion 4 of 10 CFR 50.36 since there are no specific safety analyses that credit the EFIC system for operation at less than full rated power.

LCO

All instrumentation performing an EFIC System Function in Table 3.3.11-1 shall be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable.

Four channels are required OPERABLE for all EFIC Functions. Each EFIC 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.

LCO (continued)

EFIC initiation function values for the bypass removal functions are specified in terms of applicability limits (i.e., identified in the Applicable MODES or Other Specified Conditions column of Table 3.3.11-1) for the associated trip Function. Trip setpoints are specified in the setpoint calculations or calibration procedures. The 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. Guidance used to calculate the uncertainties associated with the trip setpoints is provided in Reference 4.

The Bases for the LCO requirements of each specific EFIC Function are discussed next.

Loss of MFW Pumps

Four EFIC channels for Loss of MFW Pumps shall be OPERABLE. This ensures that upon the loss of both MFW pumps, EFW will be automatically initiated. This Function is provided as a direct digital input from the RPS and includes a bypass enable and removal function.

SG Level – Low

Four EFIC dedicated low range level transmitters per SG shall be OPERABLE with an SG Level - Low actuation Allowable Value of ≥ 9.34 inches, to generate the signals used for detection for low level conditions for EFW Initiation. This parameter is referenced to the top of the lower tube sheet and includes consideration for instrumentation error and an allowance for margin. Allowances for instrument drift and margin are included in the Limiting Trip Setpoint of ≥ 10.42 inches. A time delay of 10.4 seconds is included in the analysis to preclude inadvertent EFW actuation due to short-lived SG level transients such as Main Feedwater pump transients, Turbine Trip, etc. There is one transmitter for each of the four channels A, B, C, and D. The signals are also used after EFW is actuated to control level at approximately 31 inches when one or more RCPs are in operation. In the determination of the low level setpoint, it is desired to place the setpoint as low as possible, considering instrument errors, to give the maximum operational margin between the integrated control system setpoint and the EFW Initiation setpoint. This will minimize spurious or unwanted initiation of EFW. Credit is only taken for low level actuation for those transients which do not involve a degraded environment. Therefore, normal environment errors only are used for determining the SG Level - Low setpoint. This parameter is referenced to the top of the lower tube sheet.

SG Pressure - Low

Four EFIC channels per SG shall be OPERABLE with an SG low pressure actuation Allowable Value of ≥ 584.2 psig. 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. Small break LOCA analyses have indicated minimum secondary system pressures of greater than the above setpoint. The SG Pressure - Low Function includes a bypass enable and removal function. The bypass removal value is chosen to allow sufficient operating margin for the operator to bypass when cooling down. The above Allowable Value (i.e., 584.2 psig) includes consideration for instrumentation error and an allowance for margin. Allowances for instrument drift and additional margin are included in the trip setpoint.

LCO (continued)

SG Differential Pressure - High

Four EFIC channels for SG differential pressure shall be OPERABLE. This Function ensures that automatic EFW isolation to a depressurized SG occurs. The MSLB analysis assumes the depressurized SG is isolated when a differential pressure of 150 psid is detected. The in-plant setpoint is conservatively chosen to protect the MSLB assumptions.

RCP Status

Four EFIC channels for RCP status shall be OPERABLE. This ensures that upon the loss of four RCPs, EFW will be automatically initiated with the EFW control level automatically raised to approximately 312 inches, providing a higher SG level for establishing and maintaining natural circulation conditions. No setpoint is specified since the status indication as used by EFIC is binary in nature. The RCP Status Function includes a bypass enable and removal function from the RPS. The above parameter value (i.e., 312 inches) does contain an allowance for instrument error. This parameter is referenced to the top of the lower tube sheet.

APPLICABILITY

The EFIC System instrumentation Functions shall be OPERABLE in accordance with Table 3.3.11-1. Each Function has its own requirements that are conservative with respect to the specific accidents and conditions for which it is designed to mitigate the consequences. The parameter values provided as part of the Applicability do contain an allowance for instrument error.

The initiation of EFW on the Loss of MFW Pumps shall only be required when the unit is ≥ 10% RTP. Below 10% RTP, the EFW Initiation on low SG level will mitigate primary system overheating.

EFW Initiation on low SG level shall be OPERABLE in MODES 1, 2, and 3 which are conditions during which the SG is required for heat removal.

To avoid automatic actuation of the EFW pumps during normal heatup and cooldown transients, the low SG pressure Function can be bypassed at or below a secondary pressure of 750 psig during MODE 3 operation.

The EFW System Initiation on loss of all RCPs Function shall be operable at ≥ 10% RTP. It is possible to bypass the Function below 10% RTP; however, for most cases, the Function is kept in service until the unit is placed on the Decay Heat Removal System. To prevent inadvertent actuation of the EFW pumps, it must be bypassed prior to stopping the last RCP.

The Main Steam Line Isolation and EFW Vector Valve Control Functions shall be OPERABLE in MODES 1 and 2, and MODE 3 with SG pressure ≥ 750 psig because the SG inventory can contribute significantly to the reactor building peak pressure

APPLICABILITY (continued)

with a secondary side break. Both the normal feedwater and the EFW must be able to be isolated on each SG to limit overcooling of the primary and to limit mass and energy releases to the reactor building. Once the SG pressures have decreased below 750 psig the energy level is low and the secondary side feedwater flow rate is low or nonexistent. Also, the primary system temperatures are typically too low to allow the SGs to effectively remove energy, or are sufficiently low to allow for operator action. Therefore, EFIC instrumentation is not required to be OPERABLE.

ACTIONS

If a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or any of the transmitter, signal processing electronics, or EFIC channel cabinet modules are found inoperable, then all affected Functions provided by that channel must be declared inoperable and the unit must enter the Conditions for the particular protection Function affected.

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 failures of a single EFW Initiation or Main Steam Line Isolation instrumentation channel. This includes failure of a common instrumentation channel in any combination of the Functions.

A.1 (continued)

With one channel inoperable in one or more EFW Initiation or Main Steam Line Isolation Functions listed in Table 3.3.11-1, the channel(s) must be placed in bypass or trip within 1 hour. This Condition applies to failures that occur in a single channel, e.g., channel A, which when bypassed will remove initiate Functions within the channel from service. Since the RPS and EFIC channels are interlocked, only the corresponding channel in each system may be bypassed at any time. This feature is ensured by an electrical interlock. If testing of another channel in either the EFIC or RPS is required, the EFIC channel must be placed in trip to allow the other channel to be bypassed. With the channel in trip, the resultant logic is one-out-of-two. The Completion Time of 1 hour is adequate to perform Required Action A.1.

B.1 and B.2

Condition B applies to a situation where two instrumentation channels of the same protection functions of EFW Initiation or Main Steam Line Isolation instrumentation are inoperable. For example, Condition B applies if channel A and B of the EFW Initiation Function are inoperable.

With two EFW Initiation or Main Steam Line Isolation protection channels inoperable, one channel must be placed in bypass (Required Action B.1). Bypassing one of the remaining OPERABLE channels is not possible due to system interlocks. Therefore, the second channel must be tripped (Required Action B.2) to prevent a single failure from causing loss of the EFIC Function. The Completion Times of 1 hour are adequate to perform the Required Actions.

ACTIONS (continued)

C.1

The function of the EFW Vector Valve Control is to meet the single-failure criterion while being able to provide EFW on demand and isolate an SG when required. These conflicting requirements result in the necessity for two valves in series, in parallel with two valves in series, and a four channel valve command system. Refer to LCO 3.3.14, "Emergency Feedwater Initiation and Control (EFIC) Vector Logic."

With one EFW Vector Valve Control channel inoperable, the system cannot meet the single-failure criterion and still meet the dual functional criteria described earlier. This condition is analogous to having one EFW train inoperable. Therefore, when one vector valve control channel is inoperable, the channel must be restored to OPERABLE status (Required Action C.1) within 72 hours, which is consistent with the Completion Time associated with the loss of one train of EFW.

D.1, D.2, E.1, F.1, F.2

If the Required Actions and associated Completion Times are not met, 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 is less than 10% RTP for Functions 1.a and 1.d, MODE 4 for Function 1.b, and MODE 3 with SG pressure less than 750 psig for all other Functions. In addition, for Function 3.a, once the unit is in MODE 3, a nonapplicable condition may be achieved by closing and deactivating the valves associated with the Main Steam Line Isolation Function. 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 EFIC instrumentation Function are identified in the SRs column of Table 3.3.11-1. Individual EFIC subgroup relays must also be tested, one at a time, to verify the individual EFIC components will actuate when required. Some components cannot be tested at power since their actuation might lead to unit trip or equipment damage. These are specifically identified and must be tested when shut down. The various SRs account for individual functional differences and for test frequencies applicable specifically to the Functions listed in Table 3.3.11-1. The operational bypasses associated with each EFIC instrumentation channel are also subject to these SRs to ensure OPERABILITY of the EFIC instrumentation channel.

SR 3.3.11.1

Performance of the CHANNEL CHECK once every 12 hours provides reasonable assurance for prompt identification of a gross failure of instrumentation.
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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.11.1 (continued)

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 factors including channel instrument uncertainties. 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, where practical, to be reading at the bottom of the range and not failed downscale.

The Frequency 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 automatic bypass removal feature, required trip, interlock, and alarm functions of the channel. Setpoints for trip functions must be found within the Allowable Value. (Note that the values for the bypass removal functions are identified 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 setpoint analysis.

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 two notes. For the SG Level – Low function, if the as-found trip setpoint is found to be non-conservative with respect to the Allowable Value specified in TSs, the channel is declared inoperable and the associated TS action statement must be followed. If the as-found trip setpoint is found to be conservative with respect to the Allowable Value and outside the as-found predefined acceptance criteria band of ± 1.08 inches from the previous as-left value, but is determined to be functioning as required and can be reset to a value equal to the Limiting Trip Setpoint or a value more conservative than the Limiting Trip Setpoint, then the channel may be considered to be operable. If it cannot be determined that the instrument channel is functioning as required, the channel is declared inoperable and

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.11.2 (continued)

the associated TS actions must be followed. If the as-found trip setpoint is outside the as-found predefined acceptance criteria band, the condition must be entered into the corrective action program for further evaluation. The notes for the Channel Functional Test do not apply to the verification of the time delay.

SR 3.3.11.3

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 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 setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint analysis. The notes contained in SR 3.3.11.2 are also applicable to the CHANNEL CALIBRATION.

The Frequency is based on the assumption of at least an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. 10 CFR 50.62.

2. SAR, Chapter 7.

3. SAR, Chapter 14.

4. Instrument Loop Error Analysis and Setpoint Methodology Manual, Design Guide, IDG-001.

5. SAR, Chapter 10, Figure 10-2.

6. IEEE-279-1971, April 1972.

7. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.12 Emergency Feedwater Initiation and Control (EFIC) Manual Initiation

BASES

BACKGROUND

The EFIC manual initiation capability provides the operator with the capability to actuate EFIC Functions from the control room in the absence of any other initiation condition. Manually actuated Functions include Main Steam Line Isolation for steam generator (SG) A, Main Steam Line Isolation for SG B, and Emergency Feedwater (EFW) Actuation. These Functions are provided in the event the operator determines that an EFIC Function is needed prior to automatic actuation or in the event that EFIC does not automatically actuate when required. These are backup Functions to those performed automatically by EFIC.

The manual actuation of these functions may be performed from the Remote Switch Matrix, located on the main control boards, or from the manual actuation trip switches located on the EFIC control cabinets in the control room. The required manual actuation logic within each train consists of two manual switches (one for Trip Bus 1 and one for Trip Bus 2). When one manual trip switch is depressed, a half trip occurs. When both manual trip switches are depressed, a full trip of the train actuation occurs for that particular Function. The Remote Switch Matrix and the EFIC control cabinet trip switches perform parallel functions and, therefore, any combination of switches depressed within a train that energizes both Trip Bus 1 and Trip Bus 2 for a given Function will result in an actuation of that Function. The use of two manual trip switches for each train of actuation logic allows testing without actuating the end devices and also reduces the possibility of accidental manual actuations.

The EFIC manual initiation circuitry satisfies the manual initiation and single-failure criterion requirements of IEEE-279-1971 (Ref. 1).

APPLICABLE SAFETY ANALYSES

EFIC Functions credited in the safety analysis are automatic. However, the manual initiation Functions are required by design as backups to the automatic initiation Functions and allow operators to actuate EFW or Main Steam Line Isolation whenever these Functions are needed. Furthermore, the manual initiation of EFW and Main Steam Line Isolation may be specified in unit operating procedures.

The EFIC manual initiation functions satisfy Criterion 4 of 10 CFR 50.36 (Ref. 2).

LCO

Instrumentation on the main control board performing an EFIC manual initiation Function shall be OPERABLE.

Two manual initiation switches per actuation train (Train A and Train B) of each Function (A and B Main Steam Line Isolation, and EFW Actuation) are required to be OPERABLE. This requirement may be satisfied by the manual trip switches located on the Remote Switch Matrix on the main control board, by the trip switches located on the EFIC control cabinets, or by any combination of switches located on the Remote Switch Matrix and the EFIC control cabinets such that Trip Bus 1 and Trip Bus 2 are available for each EFIC Function in each of the two EFIC trains.

APPLICABILITY

The EFIC System Manual Initiation Function shall be OPERABLE when the associated EFIC Instrumentation Main Steam Line Isolation or EFW Initiation Function is required to be OPERABLE in accordance with Table 3.3.11-1. Each Function, i.e., Main Steam Line Isolation and EFW Initiation, has its own requirements that are based on the specific accidents and conditions for which it is designed to mitigate the consequences. See Bases for LCO 3.3.11, “EFIC Instrumentation,” for additional discussion of each Function.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each EFIC manual initiation Function.

A.1

With one required manual initiation switch of one or more EFIC Function(s) inoperable in one train, the trip bus for the associated EFIC Function(s) must be placed in the tripped condition within 72 hours. With the trip bus in the tripped condition, the single-failure criterion is met. Failure to perform Required Action A.1 could allow a single failure of another switch to prevent manual actuation of at least one of the two trains. The Completion Time allotted to trip the trip bus allows the operator to take all the appropriate actions for the failed manual initiation switch and still ensure that the risk involved in operating with the failed manual initiation switch is acceptable.

ACTIONS (continued)

B.1

With both required manual initiation switches of one or more EFIC Function(s) inoperable in one train, one manual initiation switch must be restored to OPERABLE status within 72 hours. The effect for both required switches being inoperable simultaneously is the same as for the associated EFIC components for a single train being inoperable. Therefore, the 72-hour Completion Time is appropriate since it is consistent with the Completion Times of the associated system train. The trip bus associated with the remaining inoperable manual initiation switch must be placed in the tripped condition within 72 hours (Required Action A.1). With the affected trip bus in the tripped condition, the single failure criterion is met. The Completion Time allotted to restore a trip bus or place the trip bus in the tripped condition allows the operator to take all appropriate actions for the failed manual initiation switches and still ensure that the risk involved in operating with the failed manual initiation switches is acceptable.

C.1

With one or both required manual initiation switches of one or more EFIC Function(s) inoperable in both actuation trains, one actuation train for each Function must be restored to OPERABLE status within 1 hour. With the train restored, the second train must be placed in the appropriate condition within 72 hours per Required Action A.1 or B.1, as applicable. Compliance with these actions ensures the single-failure criterion is met. The Completion Time allotted to restore the train allows the operator to take all the appropriate actions for the failed train and still ensures that the risk involved in operating with the failed train is acceptable.

D.1 and D.2

If the Required Action and the associated Completion Time is not met for any EFW Initiation Function, 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.

E.1, E.2.1, and E.2.2

If the Required Actions and associated Completion Times are not met for the Main Steam Line Isolation Function, the unit must be placed in a MODE or condition in which the requirement does not apply. This is initiated by placing the unit in MODE 3 within 6 hours and, either reducing SG pressure to less than 750 psig, or closing and deactivating all associated valves, i.e., the valves which EFIC would close if it were to actuate while OPERABLE. 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 3.3.12.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST to ensure that the trains can perform their intended functions. However, for Main Steam Line Isolation and EFW Initiation, 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 Main Steam Line Isolation or EFW Initiation during testing at power. The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY that demonstrates the rarity of more than one train failing within the same 31 day interval.

REFERENCES

1. IEEE-279-1971, April 1972.

2. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.13 Emergency Feedwater Initiation and Control (EFIC) Logic

BASES

BACKGROUND

Main Steam Line Isolation

The four emergency feedwater initiation and control (EFIC) channels sensing a steam generator (SG) low outlet pressure condition input their initiate commands to the trip logic modules. SAR, Section 7.1.4 (Ref. 1), describes the Main Steam Line Isolation Logics. The trip logic modules are identified as being part of the “A” and “B” trains and are physically located in the “A” and “B” EFIC channel cabinets. Train “A” actuation logic initiates when instrumentation channel “A” or “B” initiates and channel “C” or “D” initiates, which in simplified logic is:

Train “A” actuation = (A and C) or (A and D) or (B and C) or (B and D)

Train “B” actuation logic initiates when instrumentation channel “A” or “C” initiates and channel “B” or “D” initiates, which in simplified logic is:

Train “B” actuation = (A and B) or (A and D) or (C and B) or (C and D)

Each of the two Functions (SG A Main Steam Line Isolation, and SG B Main Steam Line Isolation) has a train “A” and a train “B” of automatic actuation logic.

Both trains "A" and "B" of the SG A Main Steam Line Isolation automatic actuation logic send closure signals to the SG A Main Steam Isolation valve.

SG B Main Steam Line Isolation automatic actuation logics respond similarly for the SG B valve.

Train “A” of the SG A Main Steam Line Isolation automatic actuation logic sends closure signals to the SG A MFW isolation valves. Similarly, Train “B” of the SG B Main Steam Line Isolation automatic actuation logic sends closure signals to the SG B MFW isolation valves.

Emergency Feedwater (EFW Initiation)

The four EFIC instrumentation channels for each of the parameters being sensed input their initiate commands to the trip logic modules. SAR, Section 7.1.4 (Ref. 1), describes the EFW initiation logic. These trip logic modules are identified as being part of the “A” and “B” trains and are physically located in the "A" and "B" EFIC channel cabinets.

BACKGROUND (continued)

EFW Initiation functions use the same actuation logic combinations as Main Steam Line Isolation. EFW initiation also occurs on Engineered Safeguards Actuation System (ESAS) actuation and on Diverse Reactor Overpressure Protection System (DROPS) actuation.

EFIC automatically initiates the EFW System when any of the following conditions exist:

a. All four reactor coolant pumps are tripped;

b. Both MFW pumps are tripped and reactor power is > 10% RTP;

c. Low level in either SG;

d. Low pressure in either SG;

e. Actuation of ESAS channels 3 or 4; or

f. Actuation of DROPS channels 1 or 2.

Vector Valve Enable Logic

The EFIC System is also responsible for sending open or close signals to the EFW control and isolation valves. SAR Section 7.1.4 (Ref. 1), describes the EFIC vector logic. The vector logic outputs are in a neutral state (neither commanding open nor close) until an enable signal is received from either train “A” or “B” of EFW Initiation. The EFIC Logic monitors the train A and B EFW Initiation logics. When an EFW Initiation occurs, the vector logic is enabled to generate open or close signals to the EFW isolation valves and close signals to the EFW control valves depending on the relative values of SG pressures. The level control module provides input to the flow controllers which control the position of the EFW control valves.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analysis discussion for the Main Steam Line Isolation and EFW Initiation Functions is discussed in the Bases for LCO 3.3.11, “EFIC Instrumentation.”

LCO

Two trains each of Main Steam Line Isolation and EFW Initiation logics shall be OPERABLE. There are only two trains 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 train.

LCO (continued)

To be considered OPERABLE, the Main Steam Line Isolation logic must send closure signals to the associated SG main steam and MFW isolation valves when the appropriate combinations of instrument channels indicate low SG pressure.

To be considered OPERABLE, the EFW Initiation logic must send initiation signals to the EFW System when the appropriate combinations of instrument channels indicate any of the following conditions exist:

a. All four reactor coolant pumps are tripped;

b. Both MFW pumps are tripped and reactor power is > 10% RTP;

c. Low level in either SG;

d. Low pressure in either SG; or

e. Actuation of ESAS channel 3 or 4.

APPLICABILITY

The EFIC Logic shall be OPERABLE when the associated EFIC Instrumentation Main Steam Line Isolation or EFW Initiation Function is required to be OPERABLE in accordance with Table 3.3.11-1. Each Function, i.e., Main Steam Line Isolation and EFW Initiation, has its own requirements that are based on the specific accidents and conditions for which it is designed to mitigate the consequences. See Bases for LCO 3.3.11, “EFIC Instrumentation,” for additional discussion of each Function.

ACTIONS

If a train is found inoperable, then all affected logic Functions provided by that train must be declared inoperable and the appropriate Condition entered for the particular protection function affected.

For this LCO, a Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each EFIC logic Function.

A.1

Condition A applies when one or more EFIC logic Functions in a single train are inoperable (i.e., train A could be inoperable for both EFIC logic Functions and Condition A would still be applicable) with all Functions in the other train OPERABLE. This Condition is equivalent to failure of one EFW and Main Steam Line Isolation train.

ACTIONS (continued)

A.1 (continued)

With one automatic actuation logic train of one or more EFIC Functions inoperable, the associated EFIC train must be restored to OPERABLE status. Since there are only two automatic actuation logic trains per EFIC Function, the condition of one train inoperable is analogous to having one train of a two train Engineered Safeguards (ES) System inoperable. The system safety function can be accomplished; however, a single failure cannot be taken. Therefore, the failed train(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 EFIC System has not been analyzed for failure of both trains of the same Function. Consequently, any combination of failures in both trains A and B 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 and its associated Completion Time is not met for the EFW Initiation Function, 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.

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

If the Required Actions and associated Completion Times are not met for the Main Steam Line Isolation Function, the unit must be placed in a MODE or condition in which the requirement does not apply. This is initiated by placing the unit in MODE 3 within 6 hours and, either reducing SG pressure to less than 750 psig, or closing and deactivating all associated valves, i.e., the valves which EFIC would close if it were to actuate while OPERABLE. 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 3.3.13.1

This SR requires the performance of a CHANNEL FUNCTIONAL TEST to ensure that the trains can perform their intended functions. This test verifies Main Steam Line Isolation and EFW Initiation automatic actuation logics are functional. 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 Main Steam Line Isolation or actuation of EFW during testing at power. The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY, which has demonstrated the rarity of more than one channel failing within the same 31 day interval.

REFERENCES

1. SAR, Chapter 7.

B 3.3 INSTRUMENTATION

B 3.3.14 Emergency Feedwater Initiation and Control (EFIC) Vector Logic

BASES

BACKGROUND

The function of the EFIC vector logic is to determine whether EFW should not be fed to one or the other steam generator. This is to preclude the continued addition of EFW to a depressurized steam generator (SG) and, thus, minimize the overcooling effects. Each vector logic may isolate EFW to one SG or the other, never both.

There are four sets of vector logic; one in each channel of EFIC. Each set of vector logic receives SG pressure information from bistables located in the input logic of the same EFIC channel. The pressure information received is:

a. SG "A" pressure less than 584.2 psig;

b. SG "B" pressure less than 584.2 psig;

c. SG "A" pressure 100 psid greater than SG "B" pressure; and

d. SG "B" pressure 100 psid greater than SG "A" pressure.

The allowable value of 584.2 psig includes consideration for instrumentation error and an allowance for margin. Allowances for instrument drift and additional margin are included in the trip setpoint. The 100 psid value is considered to be a nominal value.

Each vector logic also receives an enable signal from both EFIC train A and train B when EFW is actuated.

The vector logic develops signals for open and close control of SG "A" and "B" EFW valves.

The vector logic outputs are in a neutral state with the valves fully open until enabled by the EFW Initiation (train A or B) trip logics. When enabled, the vector logic can issue close commands to the EFW control valves and open or close commands to the EFW isolation valves per the selected channel assignments.

The valve open/close commands are determined by the relative values of steam generator pressures as follows:

PRESSURE STATUS	SG VALVES "A"	SG VALVES "B"
If SG "A" & SG "B" > 584.2 psig	Open	Open
If SG "A" > 584.2 psig & SG "B" < 584.2 psig	Open	Close
If SG "A" < 584.2 psig & SG "B" > 584.2 psig	Close	Open
If SG "A" & SG "B" < 584.2 psig		
AND		
• SG "A" & SG "B" within 100 psid	Open	Open
• SG "A" 100 psid > SG "B"	Open	Close
• SG "B" 100 psid > SG "A"	Close	Open

APPLICABLE SAFETY ANALYSES

The SAR SLB analyses, SAR Section 14.2.2.1 (Ref. 3), consider isolation of the affected SG as a function automatically performed by the EFIC System. The EFIC Vector Logic utilizes the EFW Vector Valve Control Functions (i.e., SG Pressure—Low and SG Differential Pressure—High) to determine which steam generator is associated with the rupture and provide appropriate isolation.

Additional information relating to EFIC initiation and logics may be referenced in the Bases for LCO 3.3.11, "EFIC Instrumentation."

LCO

Four channels of the EFIC vector logic module are required to be OPERABLE. The necessity for four channels is discussed in the BASES for ACTIONS. The 584.2 psig and 100 psid values were chosen as discussed in Specification B 3.3.11, "EFIC Instrumentation." The feed only good generator verification study assumed a differential pressure vector value of 150 psid. A 100 psid setpoint conservatively assumes a 50 psi (25 psi per pressure channel) margin for instrument error. Failure to meet this LCO results in not being able to meet the single-failure criterion. These values (i.e., 584.2 psig and 100 psid) do contain an allowance for instrument error.

APPLICABILITY

The EFIC Vector Logic shall be OPERABLE when the associated EFIC Instrumentation EFW Vector Valve Control Function is required to be OPERABLE in accordance with Table 3.3.11-1. The EFW Vector Valve Control Function is required to be OPERABLE in MODES 1 and 2, and in MODE 3 with SG pressure ≥ 750 psig because the SG inventory can contribute significantly to the reactor building peak pressure with a secondary side break. Both the normal feedwater and the EFW must be able to be isolated on each SG to limit overcooling of the primary and to limit mass and energy releases to the reactor building. Once the SG pressures have decreased below 750 psig, the energy level is low and the secondary side feedwater flow rate is low or nonexistent. Also, the primary system temperatures are typically too low to allow the SGs to effectively remove energy, or are sufficiently low to allow for operator action. Therefore, EFIC Vector Logic is not required to be OPERABLE in MODE 3 below 750 psig nor in MODES 4, 5, and 6.

ACTIONS

A.1

The function of the EFW control/isolation valves and the EFIC vector logic is to meet the single-failure criterion while maintaining the capability to:

a. Provide EFW on demand; and

b. Isolate an SG when required.

These conflicting requirements result in the necessity for two valves in series, in parallel with two valves in series, and a four channel valve command system.

With one channel inoperable, the system cannot meet the single-failure criterion and still meet the dual functional criteria previously described. Therefore, when one vector valve logic channel is inoperable, the channel must be restored to OPERABLE status within 72 hours. This is analogous to having one EFW train inoperable; wherein a 72 hour Completion Time is provided by the Required Actions of LCO 3.7.5, "EFW System." As such, the Completion Time of 72 hours is based on engineering judgment.

B.1 and B.2

If Required Action A.1 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 SG pressure must be reduced to < 750 psig 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 3.3.14.1

SR 3.3.14.1 is the performance of a CHANNEL FUNCTIONAL TEST every 31 days. This test demonstrates that the EFIC vector logic performs its function as desired. The Frequency is based on operating experience with respect to channel OPERABILITY that demonstrates the rarity of more than one channel failing within the same 31 day interval.

REFERENCES

None.

B 3.3 INSTRUMENTATION

B 3.3.15 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 monitor and 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 Accidents (DBAs).

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 in SAR Table 7-11A (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 I variables.

Type A variables are specified because they provide the primary information that permits the control room operator to take specific manually controlled actions that are required when no automatic control is provided and that are required for safety systems to accomplish their safety functions for DBAs.

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the potential for causing a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

These key variables are also identified in SAR Table 7-11A (Ref. 1).

BACKGROUND (continued)

The specific instrument Functions listed in Table 3.3.15-1 are discussed in the LCO Bases Section.

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 abnormal and emergency operating procedures. These variables include 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;
- 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.

SAR Section 7.3.4 (Ref. 4) documents the results of the Regulatory Guide 1.97 analysis process which identified Type A and Category I non-Type A variables.

In MODE 1, PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODES 2 and 3, Category I, 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 I, non-Type A variables are important for reducing public risk, and satisfy Criterion 4 of 10 CFR 50.36 (Ref. 5).

LCO

LCO 3.3.15 requires two OPERABLE channels for all but one Function 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. Furthermore, provision of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of

LCO (continued)

displayed information. When a channel includes more than one qualified control room indication, such as both an indicator and a recorder, or an indicator and Safety Parameter Display System (SPDS) readout, etc., only one indication is required for channel OPERABILITY.

The exception to the two channel requirement is reactor building isolation valve position. In this case, the important information is the status of the reactor building penetrations. The LCO requires one position indicator for each automatic reactor building 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 reactor building 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 (See Table 3.3.15-1, Note (a)).

Each of the specified instrument Functions listed in Table 3.3.15-1 are discussed below:

1. Wide Range Neutron Flux

   Wide Range Neutron Flux indication is a Type B, Category I variable provided to verify reactor shutdown. The Wide Range Neutron Flux channels consist of two channels of qualified fission chamber based instrumentation (Gamma-Metrics) with readout on one recorder and on the SPDS. The channels provide indication over a range of 10^{-8} to 100% full power (Ref. 1).

2. Reactor Coolant System (RCS) Hot Leg Temperature

   RCS Hot Leg Temperature instrumentation is a Type A Category I variable provided for verification of core cooling and long term surveillance including determining when to secure reactor coolant pumps following a LOCA. Reactor outlet temperature inputs are provided by two fast response resistance elements and associated transmitters in each loop. The two channels provide readout on one indicator and one recorder and on the SPDS. The channels provide indication over a range of 50°F to 700°F.

3. RCS Hot Leg Level

   RCS Hot Leg Level instrumentation is a Type B, Category I variable provided to support operator diagnosis of inadequate core cooling and tracking reactor coolant inventory. Each channel monitors level from one (1) wide range and any two (2) of four (4) narrow range transmitters per hot leg. Channel OPERABILITY requires a minimum of one wide range and any two of the narrow range transmitters in the same channel OPERABLE. In addition, reference leg temperature inputs and core exit thermocouple average temperature are used for density compensation of the level. The system is

LCO (continued)

designed to infer the water level in the hot legs during no-flow conditions. The channels provide readout on two indicators and on the SPDS. The channels provide indication over a unit elevation range of 368 feet 6 inches to 417 feet 6 inches.

4. RCS Pressure (Wide Range)

RCS Pressure (Wide Range) instrumentation is provided for verification of core cooling and RCS integrity long term surveillance.

Wide range RCS loop pressure is measured by pressure transmitters with a span of 0 psig to 3000 psig. The pressure transmitters are located inside the RB. Redundant monitoring capability is provided by two channels of instrumentation. This control room display, consisting of one indicator and one recorder, and the SPDS is the primary indication used by the operator during an accident. Therefore, the accident monitoring specification deals specifically with this portion of the instrument string.

RCS Pressure is a Type A, Category I variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator (SG) tube rupture or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting SG pressure or level, would use this indication. In addition, high pressure injection (HPI) flow is throttled based on RCS Pressure and subcooled margin.

5. Reactor Vessel Water Level

Reactor Vessel Water Level instrumentation is a Type B, Category I variable and is provided for verification and long term surveillance of core cooling. The reactor vessel level monitoring system provides an indication of the liquid level above the fuel.

The level range extends from the top of the vessel dome down to the top of the fuel alignment plate. The response time is short enough to track the level during small break LOCA events. The resolution is sufficient to show the initial level drop, the key locations near the hot leg elevation, and the lowest levels just above the fuel. This provides the operator with adequate indication to track the progression of the accident and to detect the consequences of its mitigating actions or the functionality of automatic equipment.

The Reactor Vessel Water Level channels consist of two redundant Radcal Level Instruments (RLIs) (each containing nine (9) axially distributed level sensors and one reactor vessel head temperature thermocouple to detect reactor coolant inventory above the core), and a data acquisition system with readout on two indicators. When Reactor Coolant Pumps are running, all except the dome sensors are interlocked to read "invalid" due to flow induced

LCO (continued)

variables that may offset the sensor outputs. Channel OPERABILITY requires a minimum of three sensors in the upper plenum region and two sensors in the dome region OPERABLE. Readout for this parameter is also provided on the SPDS.

6. Reactor Building Water Level (Wide Range)

Reactor Building Water Level (Wide Range) instrumentation is a Type B, Category I variable and is provided for verification of net positive suction head (NPSH) for the recirculation phase. The Reactor Building Water Level instrumentation consists of two channels with readout on two indicators and one recorder and on the SPDS. The channels provide water level indication over a range of 0 to 144 inches.

7. Reactor Building Pressure (Wide Range)

Reactor Building Pressure (Wide Range) instrumentation is a Type B, Category I variable and is provided for verification of RCS and reactor building OPERABILITY. Reactor Building Pressure instrumentation consists of two channels with readout on two indicators and one recorder and on the SPDS. The channels provide pressure indication over a range of 0 to 210 psia (-15 to 195 psig).

8. Automatic Reactor Building Isolation Valve Position

Automatic Reactor Building Isolation Valve Position is a Type B, Category I variable and is provided for verification of the isolation status of the reactor building penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each automatic isolation valve in a reactor building penetration flow path, i.e., two total channels of position indication for a penetration flow path with two automatic valves. For reactor building penetrations with only one automatic valve having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to verify the isolation status of each isolable penetration via indicated status of the automatic valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the isolation valve(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. 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 isolation valve position PAM instrumentation consists of Class 1E position switches for each automatic reactor building isolation valve. These switches provide "closed -not closed" indication via indicating lights in the control room.

LCO (continued)

9. Reactor Building Area Radiation (High Range)

Reactor Building Area Radiation (High Range) instrumentation is a Type E, Category I variable and is 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. The Reactor Building Area Radiation instrumentation consists of two channels with readout on two indicators and one recorder and on the SPDS. The channels provide high radiation indication over a range of 1 to 10^8 R/hour gamma; however, the required range is only 1 to 10^7 R/hour gamma.

10. Deleted

11. Pressurizer Level

Pressurizer Level instrumentation is a Type D, Category I variable and is used in combination with other system parameters to determine whether to terminate safety injection (SI), if still in progress, or to reinitiate SI 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. The Pressurizer Level instrumentation consists of two channels with readout on one indicator and one recorder and on the SPDS. The channels provide level indication over a range of 87 to 407 inches (bottom to top).

12. Steam Generator Water Level

Steam Generator Water Level instrumentation is a Type A, Category I variable provided to monitor operation of RCS heat removal via the SG and to determine the affected SG for isolation following a SGTR event. The indication of SG level is provided by the low range and high range level instrumentation, covering a span of 6 inches to 500 inches above the lower tubesheet. The measured differential pressure is displayed in inches of water.

The Steam Generator Water Level instrumentation consists of two channels (A and B) for each steam generator for the low range and two channels for each steam generator for the high range with readout on four dual indicators (one

SG channel with both ranges per indicator) and on the SPDS. The Low Range channels provide level indication over a range of 6 to 156 inches of water and the High Range channels provide level indication over a range of 102 to 500 inches of water. Each range of water level instrumentation for each steam generator is considered a separate Function of PAM Instrumentation. Two additional channels (C and D) also monitor SG water level for EFIC but these channels are not required as PAM instrumentation.

SG high range level indication is used by the operator to manually raise and control SG level to establish reflux boiling (boiler condenser) heat transfer. Operator action is initiated on a loss of subcooled margin. Feedwater flow is increased until the indicated level reaches the reflux boiling (boiler condenser) setpoint.

LCO (continued)

13. Steam Generator Pressure

Steam Generator Pressure instrumentation is a Type A, Category I variable provided to support operator diagnosis of a design basis steam generator tube rupture to identify and isolate the affected SG. In addition, SG pressure is a key parameter used by the operator to evaluate primary-to-secondary heat transfer. For example, the operator may use this indication to control the primary system cooldown following a steam line break accident or a small break loss of coolant accident (LOCA).

Steam generator pressure measurement is provided by two pressure transmitters per SG. The channels provide readout on two indicators (one per SG) and two dual pen recorders (one per SG) and on the SPDS. The channels provide pressure indication over a range from 0 to 1200 psig. The pressure instrumentation for each steam generator is considered a separate Function of PAM Instrumentation.

14. Condensate Storage Tank (QCST) Level

QCST Level instrumentation is a Type A, Category I variable and is provided to ensure a readily available, condensate quality water supply for EFW. Inventory is monitored by a 0 to 30 feet level indication. QCST Level is displayed on one control room indicator and one recorder, and on the SPDS.

QCST Level is the primary indication used by the operator to identify loss of QCST volume and replenish the QCST or align suction of the EFW pumps to the safety related source, i.e., service water.

15. Borated Water Storage Tank Level

Borated Water Storage Tank (BWST) Level instrumentation is a Type A, Category I variable provided to support action for long term cooling requirements, i.e., to determine when to initiate the switch-over of the core cooling pump suction from the BWST to sump recirculation. BWST Level measurement is provided by two channels with readout on two indicators and one recorder and on the SPDS. The level transmitters are calibrated over a range of 0 to 45 feet. The “0” reference level is the level instrument tap, which is approximately 5 inches above the bottom of the tank.

16. Core Exit Temperature

Core Exit Temperature is a Type C, Category I variable and is provided for verification and long term surveillance of core cooling. Twenty-four (24) qualified core exit thermocouples (CETs) are provided with six (6) located in each core quadrant. Two CETs are required in each core quadrant and readout is provided on two indicators and on the SPDS. The channels provide core exit temperature indication over a range of 50 to 2300°F. This Function is specified on a “CETs per quadrant” basis. Therefore, each quadrant of required CETs is considered a separate Function for Condition entry.

LCO (continued)

17. Emergency Feedwater Flow

    EFW Flow instrumentation is a Type D, Category I variable and is provided to monitor operation of RCS heat removal via the SGs. One channel is provided for each flow path of an EFW pump to each SG, i.e., each pump feeds both SGs so there are four flow paths. The channels provide indication of EFW Flow to each SG over a range of 0 to 900 gpm. Each transmitter provides an input to a control room indicator (four indicators total) and to the SPDS. Flow measurement to each steam generator is considered a separate Function of PAM Instrumentation.

    EFW Flow is the primary indication used by the operator to verify that the EFW System is delivering flow to the correct SG.

18. High Pressure Injection Flow

    See the discussion for Function 19 below.

19. Low Pressure Injection Flow

    High and Low Pressure Injection Flow instrumentation is a Type A, Category I variable provided to support action for long term cooling requirements.

    HPI flow may be throttled based on RCS pressure, subcooled margin and pressurizer level, and to balance flow rates between the injection lines. LPI flow information is used to determine when it is acceptable to terminate HPI. High and Low Pressure Injection Flow measurement is provided by two channels each with readout on two indicating recorders for high pressure injection (HPI), and with readout on two indicators and one recorder for low pressure injection (LPI) and on the SPDS. Each HPI channel includes four instruments (one per flow path) which provide flow indication over a range from 0 to 200 gpm, and the LPI channels provide flow indication over a range from 0 to 4500 gpm.

20. Reactor Building Spray Flow

    Reactor Building Spray Flow instrumentation is a Type A, Category I variable provided to support action for long term reactor building cooling requirements (e.g., maintain NPSH) and iodine removal. Reactor Building Spray Flow measurement is provided by two channels with readout on two indicators and one recorder and on the SPDS. The channels provide flow indication over a range from 0 to 2000 gpm.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required for safe shutdown and to determine that safety systems are performing their intended function when required. 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

The ACTIONS are modified by two Notes. Note 1 is added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident utilizing alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 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 3.3.15-1. 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. This Note is also applicable for Table 3.3.15-1 items 12a, 12b, 12c, 12d, 13a, 13b, 17a and 17b, each of which is considered a separate 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, 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

Required Action B.1 specifies initiation of actions to prepare and submit a Special Report to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. The Special Report is to be submitted in accordance with 10 CFR 50.4 within 30 days of entering Condition B. 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. The Completion Time of "Immediately" for Required Action B.1 identifies the start of the “clock” for submittal of the Special Report. Condition B is modified by a Note requiring Required Action B.1 to be completed whenever the Condition is entered. The Note ensures the requirement to prepare and submit the report is completed. Restoration alone per Required Action A.1 after the initial Completion Time of 30 days does not alleviate the need to report the extended inoperability to the NRC.

ACTIONS (continued)

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 probability that the PAM Function will be unavailable should an accident occur.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.15-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action and associated Completion Time of Condition C, 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 C are not met and Table 3.3.15-1 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 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

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.15-1 directs entry into Condition F, alternate means of monitoring the parameter should be applied and the Required Action is not to shut down the unit but rather to initiate actions to prepare and submit a Special Report to the NRC. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate 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. The Special Report is to be submitted in accordance with 10 CFR 50.4 within 30 days of entering Condition F.

Both the RCS Hot Leg Level and the Reactor Vessel Level are methods of monitoring for inadequate core cooling.

ACTIONS (continued)

F.1 (continued)

The alternate means of monitoring the Reactor Building Area Radiation (High Range) consist of a combination of installed area radiation monitors and portable instrumentation.

The Completion Time of “Immediately” for Required Action F.1 identifies the start of the “clock” for submittal of the Special Report.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs apply to each PAM instrumentation Function in Table 3.3.15-1.

SR 3.3.15.1

Performance of the CHANNEL CHECK once every 31 days for each required instrumentation channel that is normally energized provides reasonable assurance for prompt identification of a gross failure of instrumentation. 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. The high radiation instrumentation should be compared with similar unit instruments located throughout the unit. For the reactor building hi-range radiation monitor, the CHANNEL CHECK should also note the detector's response to the keep alive source.

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, where practical, 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.15.2

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.

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, and 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. Finally, the detectors are of simple construction, and any failures in the detectors will be apparent as change in channel output.

For the Reactor Building Area Radiation instrumentation, 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.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detector (RTD) sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit 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 consistency with the typical industry refueling cycle and is justified by the assumption of at least an 18 month calibration interval in the determination of the magnitude of equipment drift.

REFERENCES

1. SAR, Table 7-11A.

2. Regulatory Guide 1.97.

3. NUREG-0737, 1979.

4. SAR, Section 7.3.4.

5. 10 CFR 50.36.

B 3.3 INSTRUMENTATION

B 3.3.16 Control Room Isolation - High Radiation

BASES

BACKGROUND

The principal function of the Control Room Isolation - High Radiation 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 initiated to provide isolation and shutdown the unit's normal control room ventilation supply fan.

The control room isolation signal is provided by two independent radiation monitoring systems; one associated with each unit. The Unit 1 radiation monitor is in the Unit 1 control room normal supply duct. The Unit 2 radiation monitor is in the Unit 2 control room normal supply duct. If a radioactivity concentration significantly above normal background level is detected, the unit monitor will initiate a shutdown of the unit's normal duty supply fans, place both unit's ventilation dampers in their recirculation mode, and start the unit's Control Room Emergency Ventilation System (CREVS) supply fan.

The trip setpoints are chosen sufficiently below hazardous radiation levels to minimize operator exposure during an accident and sufficiently above normally experienced background levels to minimize spurious actuation. The habitability systems functional design bases are provided in the ANO Unit 2 SAR, Section 6.4 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The control room must be maintained habitable during post accident operations and recovery. The CREVS is a shared system which provides a filtered makeup air source for the common control room habitability envelope from which the unit can be operated following an uncontrolled release of radioactivity. Upon receipt of a high radiation signal, the associated normal ventilation supply fans are shutdown, the control room isolation dampers are closed to isolate both normal outside air intakes, and the associated CREVS train emergency filtration function is initiated. Operator action is necessary to shut down one train of CREVS (if both actuate) in order to prevent operator doses greater than identified by the habitability analysis. Operator action is also necessary to verify that at least one door between the Unit 1 and Unit 2 control rooms is open to provide appropriate pressurization and recirculation.

APPLICABLE SAFETY ANALYSES (continued)

In MODES 1, 2, 3, and 4, the radiation monitor isolation of the control room habitability envelope and actuation of the CREVS provides a habitable environment for the operators following a design basis accident or any event with a significant release of radioactivity.

During movement of irradiated fuel assemblies, the radiation monitor isolation of the control room habitability envelope and actuation of the CREVS provides a habitable environment for the operators following a fuel handling accident.

The Control Room Isolation-High Radiation satisfies Criterion 3 of 10 CFR 50.36 (Ref. 2).

LCO

The LCO requires that instrumentation necessary to initiate the CREVS is OPERABLE. Two channels of Control Room Isolation-High Radiation are required to be OPERABLE to provide actuation capability from high radiation either entering the control room habitability envelope via the Unit 1 normal supply duct (2RITS-8001) or entering the control room habitability envelope via the Unit 2 normal supply duct (2RITS-8750-1).

Trip setpoints are specified in the unit specific procedures. The setpoints are selected to ensure the as-found setpoint measured by the CHANNEL FUNCTIONAL TEST does not exceed the Allowable Value if the bistable is performing as required. The trip setpoint for this parameter does not include additional allowances for instrument uncertainties. Therefore, the trip setpoint and Allowable Value are the same.

APPLICABILITY

The control room isolation capability on high radiation shall be OPERABLE in MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies in any MODE. If a radioactive release were to occur during any of these conditions, the control room would have to remain habitable to ensure continued reactor control capability from the control room.

ACTIONS

A.1

Condition A applies to inoperability of one channel of the Control Room Isolation - High Radiation function in MODE 1, 2, 3, or 4.

With one channel of Control Room Isolation-High Radiation function inoperable, one channel remains OPERABLE to provide an automatic actuation function. Since the probability of an event which would be detected by only one of the radiation monitors is low, operation of the unit may continue for up to 7 days. If the CREVS actuation instrumentation is not returned to OPERABLE status, the unit ventilation system must be placed, within the 7 days, in a state equivalent to that which occurs after the high radiation actuation has occurred with one OPERABLE train of the CREVS in the emergency recirculation mode of operation. Reactor operation may then continue indefinitely in this state. The 7 day Completion Time is sufficient to restore most causes of inoperable actuation instrumentation.

B.1

Condition B applies to inoperability of both channels of the Control Room Isolation-High Radiation function in MODE 1, 2, 3, or 4.

With both channels of Control Room Isolation - High Radiation inoperable, the ventilation system must be placed in a condition that does not require the isolation to occur, i.e., in a state equivalent to that which occurs after the high radiation isolation has occurred with one OPERABLE train of the CREVS in operation. Reactor operation can continue indefinitely in this state. 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 CREVS cannot be placed into the emergency recirculation mode 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.

ACTIONS (continued)

D.1 and D.2

Required Action D.1 is the same as discussed earlier for Condition A, except for Completion Time. If the CREVS cannot be placed into recirculation mode while moving irradiated fuel assemblies, then Required Action D.2 suspends actions that could lead to an accident that could release radioactivity resulting from a fuel handling accident.

Required Action D.2 places the irradiated fuel in a safe and stable configuration in which it is less likely to experience an accident that could result in a release of radioactivity. The irradiated fuel must be maintained in these conditions until the automatic isolation capability is returned to operation or when manual action places one train of the CREVS into the emergency recirculation mode. The Completion Time of "Immediately" 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.

Note that in certain circumstances, such as fuel handling in the fuel handling area during power operation, both Condition A or B and Condition D may apply in the event of channel failure(s).

SURVEILLANCE REQUIREMENTS

SR 3.3.16.1

Performance of a CHANNEL CHECK for the Control Room Isolation - High Radiation actuation instrumentation once every 12 hours provides reasonable assurance for prompt identification of a gross failure of instrumentation. Performance of the CHANNEL CHECK helps ensure that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Acceptance criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties. 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. The Frequency is based on operating experience that demonstrates channel failure is rare.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.16.2

A Note allows a channel to be inoperable for up to 3 hours for surveillance testing without entering the associated Conditions and Required Actions, although during this time period it cannot actuate a control room isolation. This is based on the average time required to perform channel surveillance. It is not acceptable to remove channels from service for more than 3 hours to perform required surveillance testing without declaring the channel inoperable.

SR 3.3.16.2 is the performance of a CHANNEL FUNCTIONAL TEST once every 31 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. Any setpoint adjustment shall be consistent with the setpoint requirements.

The 31 day Frequency is based on operating experience which indicates that the instrumentation usually passes the CHANNEL FUNCTIONAL TEST when performed on a monthly basis.

SR 3.3.16.3

This SR requires the performance of a CHANNEL CALIBRATION to ensure that the instrument channel remains operational with the correct setpoint.

CHANNEL CALIBRATION is a complete check of the instrument loop and 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 drifts between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATION must be performed consistent with the setpoint requirements.

The Frequency is based on the assumption of at least an 18 month calibration interval in the determination of the magnitude of equipment drift and is consistent with the typical refueling cycle.

REFERENCES

1. ANO-2 SAR, Section 6.4.

2. 10 CFR 50.36.

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 abnormalities 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 that used as the initial pressure in the analyses. Considering only pressure, a pressure greater than the minimum specified will produce a higher DNBR; and a pressure lower than the minimum specified will produce a lower DNBR.

The LCO for maximum RCS coolant hot leg temperature is consistent with the initial hot leg temperature in the analyses. Considering only temperature, a hot leg temperature lower than that specified will produce a higher DNBR; and a temperature higher than that specified will produce a lower DNBR.

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. Considering only flow rate, a higher RCS flow rate than that specified will produce a higher DNBR; and a lower RCS flow rate will produce a lower DNBR.

APPLICABLE SAFETY ANALYSES

The requirements of LCO 3.4.1 represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Refs. 1 and 2). The safety analyses have shown that transients initiated from the limits of this LCO will meet the DNBR criteria of $\geq$ 1.30, $\geq$ 1.18, or $\geq$ 1.132 for the BAW-2, the BWC, or the BHTP critical heat flux correlation, respectively. For the locked rotor accident, the minimum DNB ratio is not less than applicable critical heat flux correlation limit, or fuel cladding is shown to experience no significant temperature excursions. These are the acceptance criteria 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 include loss of coolant flow events and dropped or stuck control

APPLICABLE SAFETY ANALYSES (continued)

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," LCO 3.2.4, "QUADRANT POWER TILT (QPT)," LCO 3.1.4, "CONTROL ROD Group Alignment Limits," and LCO 3.1.6, "AXIAL POWER SHAPING ROD (APSR) Alignment Limits."

The safety analyses to establish reload operating limits are performed using nominal values for RCS coolant average temperature, core outlet pressure, and RCS flow rate and core power level with appropriate application of associated uncertainty. Consistent with Statistical Core Design (SCD) methodology, applicable random parametric uncertainties are combined statistically. As necessary, bias parameters are included deterministically. The RCS temperature and pressure are measured in the hot leg. The surveillance criteria specified in the COLR include adjustment for measurement location. The COLR specified hot leg temperature is the maximum allowed so that the analysis value is not exceeded. The COLR specified hot leg pressure and flow are the minimum allowed so that the analysis values are not exceeded.

Analyses have been performed to establish the pressure, temperature, and flow rate requirements for two pump, three pump and four pump operation. The flow limits for two pump and 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 steady state limits on DNBR related parameters are provided in Safety Limit (SL) 2.1.1, "Reactor Core SLs." Those limits are less restrictive on plant operations 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, a check must be performed to determine whether an SL may have been exceeded.

The RCS DNB limits satisfy Criterion 2 of 10 CFR 50.36 (Ref. 4).

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 surveillance criteria for pressure, temperature, and flow rate as specified in the COLR have been appropriately adjusted for the measurement location and for instrument error consistent with supporting analysis.

APPLICABILITY

In MODE 1, the limits on RCS pressure, RCS hot leg temperature, and RCS flow rate must be maintained during steady state 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 significant concern.

The Note indicates the limit on RCS pressure may be exceeded during short term operational pressure transients resulting from a THERMAL POWER change > 5% RTP per minute. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, for transients initiated from power levels less than the Allowable Thermal Power, increased DNBR margin exists to offset the temporary pressure variations.

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 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 eliminate the potential for violation of the minimum DNBR limit.

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 and associated Completion Time 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis assumptions.

The 6 hour Completion Time is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

The RCS pressure value specified is dependent on the number of pumps in operation and has been adjusted to account for the pressure difference between the core exit and the measurement location. 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

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 available flow indications. 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.

SR 3.4.1.4

Measurement of RCS total flow rate 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 specified in the COLR.

The Frequency of 18 months reflects the importance of verifying flow after a refueling outage when the core has been altered or RCS flow characteristics may have been modified, which may have caused change of flow.

The Surveillance is modified by a Note that indicates the SR does not need to be performed until stable thermal conditions are established at higher power levels (i.e., ≥ 90% RTP). The Note provides for measurement of the flow rate at normal operating conditions at power in MODE 1. The Surveillance may be performed at low power or in MODE 2 or below. However, at low or zero power conditions, the indications are less accurate and significant penalties for uncertainties may be necessary. Performance of the calorimetric heat balance at a high power level and normal operating conditions provides for the most accurate flow verification.

REFERENCES

1. SAR, Chapter 14.

2. SAR, Section 3A.6.

3. BAW-10179P-A, Rev. 6, August 2005.

4. 10 CFR 50.36.

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;

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

The reactor coolant moderator temperature coefficient used in core operating and accident analysis is typically defined for the normal (average) operating temperature range (532°F to 579°F). 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 (Tavg) using inputs of the same range. Nominal Tavg for making the reactor critical is 532°F. Safety and operating analyses for lower temperatures have not been performed for all possible scenarios.

APPLICABLE SAFETY ANALYSES

There are no accident analyses that dictate the minimum temperature for criticality, but all low power safety analyses assume initial temperatures near the 525°F limit (Ref. 1).

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36 (Ref. 2).

LCO

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. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

LCO (continued)

The LCO limit of 525°F has been selected to be within the instrument indicating range (520°F to 620°F). This parameter value is considered to be a nominal value. No additional allowances for instrument uncertainty are required in the implementing procedures.

APPLICABILITY

The reactor has been designed and analyzed to be critical in MODES 1 and 2 only with Tavg ≥ 525°F. Criticality is not permitted in any other MODE. Therefore, this LCO is applicable in MODE 1 and MODE 2.

ACTIONS

A.1

With Tavg 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 3 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 Tavg can be restored within the 30 minute time period, shutdown is not required.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS average temperature is required to be verified at or above 525°F every 12 hours. The SR to verify RCS average temperature every 12 hours takes into account indications 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.

RCS T_{avg} is normally calculated as the average of the unit T_{hot} (hot temperature average of loops A and B) and the unit T_{cold} (cold temperature average of loops A and B). During operation with 3 RCPs in operation, T_{avg} is calculated as the average of the loop T_{hot} and loop T_{cold} in the loop that has 2 RCPs running.

REFERENCES

1. SAR, Chapter 14.

2. 10 CFR 50.36.

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, and unit transients. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

Figures 3.4.3-1, 3.4.3-2, and 3.4.3-3 contain P/T limit curves for heatup, cooldown, inservice hydrostatic testing, and physics testing at RCS temperatures ≤ 525°F, and the maximum rate of change of reactor coolant temperature. The methods and criteria employed to establish operating pressure and temperature limits are described in BAW-10046A (Ref. 1). These limit curves are applicable through thirty-one effective full power years (EFPY) of operation. The pressure limit is adjusted for the pressure differential between the point of system pressure measurement and the limiting component for the various operating reactor coolant pump combinations.

Each P/T curve defines an acceptable region for normal operation below and to the right of the limit curve. The curves are used to develop operational guidance for use during heatup or cooldown maneuvering.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel. The vessel is the component most subject to brittle failure due to the fast neutron embrittlement it experiences during power operation, 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 reactor coolant pressure boundary (RCPB) materials. Reference 2 requires an adequate margin to brittle failure during normal operation, abnormalities, 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).

BACKGROUND (continued)

The major components of the reactor coolant pressure boundary have been analyzed in accordance with Appendix G to 10CFR50. Results of this analysis, including the actual pressure-temperature limitations of the reactor coolant pressure boundary, are given in FTI Document 77-1258569-01 (Ref. 5). The service period was reduced by one effective full power year from that assumed in Reference 5 to be conservative with respect to independent calculations performed by the NRC staff. The limiting weld material is being irradiated as part of the B&W Owners Group Integrated Reactor Vessel Material Surveillance Program and the identification and locations of the capsules containing the limiting weld material is discussed in the latest revision to B&W report, BAW-1543 (Rev. 6). The chemical composition of the limiting weld material is reported in the B&W report, BAW-2121P (Rev. 7). The effect of neutron irradiation on the nil ductility reference temperature (RT_{NDT}) of the limiting weld material is reported in FTI Calculations 32-1245917-00 and 32-1257716-00 (Rev. 8).

The actual shift in the RT_{NDT} of the vessel beltline region material will be established periodically by removing and evaluating the irradiated reactor vessel material surveillance specimens, in accordance with Appendix H of 10 CFR 50 (Ref. 9). These specimens are installed near the inside wall of this or a similar reactor vessel in the core region. The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 3.

Prior to reaching thirty-one effective full power years of operation, Figures 3.4.3-1, 3.4.3-2, and 3.4.3-3 must be updated for the next service period in accordance with 10 CFR 50, Appendix G. The service period must be of sufficient duration to permit the scheduled evaluation of a portion of the surveillance data scheduled in accordance with the latest revision of Topical Report BAW-1543 (Ref. 6). The highest predicted adjusted reference temperature of all the beltline region materials is used to determine the adjusted reference temperature at the end of the service period. The basis for this prediction is submitted for NRC staff review at least 90 days prior to the end of the service period.

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 inservice hydrostatic testing curve uses different safety factors (per Ref. 3) than the heatup and cooldown curves. The testing curve also extends to the RCS design pressure of 2500 psia.

BACKGROUND (continued)

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.

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. 10) 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.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36 (Ref. 11).

LCO

The three elements of this LCO are:

a. The limit curves for heatup, cooldown, normal operation, PHYSICS TESTING and inservice hydrostatic testing;

b. Limits on the rate of change of temperature; and

c. Limits on RCP combinations.

The LCO limits apply to all components of the RCS, except the pressurizer (as indicated by the Note). These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

LCO (continued)

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

The limit curves include the limiting pressure differential between the point of system pressure measurement and the pressure on the reactor vessel region controlling the limit curve. However, the limit curves are not adjusted for possible instrument error and should not be used for operation.

The heatup and cooldown rates stated are intended as the maximum changes in temperature in one direction in the stated time periods. The actual temperature linear ramp rate may exceed the stated limits for a shorter time period provided that the maximum total temperature difference does not exceed the limit and that a temperature hold is observed to prevent the total temperature difference from exceeding the limit for the stated time period.

The acceptable P/T combinations are below and to the right of the limit curves which are applicable for the first 31 EFPY. The limit curves include the limiting pressure differential between the point of system pressure measurement and the pressure on the reactor vessel region controlling the limit curve. However, the limit curves are not adjusted for possible instrument error and should not be used for operation.

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:

a. The magnitude of the departure from the allowable operating P/T regime or the magnitude 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 inservice hydrostatic testing, their applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

ACTIONS

A.1 and A.2

With RCS pressure and temperature not within criticality limit of Figure 3.4.3-1 during PHYSICS TESTS with RCS temperature ≤ 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 3 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 RCS pressure and temperature can be restored within the 30 minute time period, shutdown is not required.

B.1 and B.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 evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation beyond the 72 hour Completion Time of Required Action B.2. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. The evaluation must be completed, documented, and approved in accordance with established unit procedures and administrative controls.

ASME Code, Section XI, Appendix E (Ref. 10) may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline. The evaluation must extend to all components of the RCPB.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate beyond the 72 hour Completion Time.

Condition B is modified by a Note requiring Required Action B.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 B.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

ACTIONS (continued)

C.1 and C.2

If a Required Action and associated Completion Time of Condition B are not met, the unit 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. Performing this examination in the required MODES reduces the RCS at reduced pressure and temperature, which decreases the possibility of propagation of undetected flaws.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action C.1 and Required Action C.2 must be initiated 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 C.1 and C.2. A favorable evaluation must be completed 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 initiated without completing these Required Actions.

Pressure and temperature are reduced by bringing the unit 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 unit systems.

D.1 and D.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 promptly in a controlled manner.

In addition to restoring operation to within limits, an evaluation is required to verify that the RCPB integrity remains acceptable. The evaluation 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.

ACTIONS (continued)

D.1 and D.2 (continued)

ASME Code, Section XI, Appendix E (Ref. 10), may also be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition D is modified by a Note requiring Required Action D.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 D.1, is insufficient because higher than analyzed stresses may have occurred and may have affected RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1, SR 3.4.3.2, SR 3.4.3.3, and SR 3.4.3.4

Verification that operation is within the limits of the appropriate figure 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 inservice hydrostatic testing may be discontinued when the definition given in the relevant unit procedure for ending the activity is satisfied.

The acceptable P/T combinations are below and to the right of the limit curves which are applicable for the first 31 EFPYs. The limit curves include the limiting pressure differential between the point of system pressure measurement and the pressure on the reactor vessel region controlling the limit curve. However, the limit curves are not adjusted for possible instrument error and should not be used for operation (as identified in Note 1 on each applicable Figure).

SR 3.4.3.1 is modified by a Note that requires this SR to be performed only during system heatup operations with fuel in the reactor vessel. This SR refers to Figure 3.4.3-1 which provides applicable heatup limitations, including reactor coolant pump (RCP) operating restrictions and allowable heatup rates. Figure 3.4.3-1 Note 2 identifies that when the decay heat removal system is operating with no RCPs operating, the indicated DHR system return temperature to the reactor vessel is the appropriate temperature indicator.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.3.1, SR 3.4.3.2, SR 3.4.3.3, and SR 3.4.3.4 (continued)

SR 3.4.3.2 is modified by a Note that requires this SR to be performed only during system cooldown operations with fuel in the reactor vessel. This SR refers to Figure 3.4.3-2 which provides applicable cooldown limitations, including reactor coolant pump (RCP) operating restrictions and allowable cooldown rates. During system cooldown operations with fuel in the reactor vessel, the RCPs are eventually removed from service. Figure 3.4.3-2 Note 2 identifies that when the decay heat removal system is operating with no RCPs operating, the indicated decay heat removal system return temperature to the reactor vessel is the appropriate temperature indicator. Figure 3.4.3-2 Note 2 also indicates that a maximum step temperature change of 25°F is allowable when removing all RCPs from operation with the decay heat removal system operating. The step temperature change is defined as the reactor coolant temperature (prior to stopping all RCPs) minus the decay heat removal system return temperature to the reactor vessel (after stopping all RCPs). The step change of 25°F is applicable only during transition from RCP operation to DHR. This step change must be included when determining the cooldown rate.

SR 3.4.3.3 is modified by a Note that requires this SR to be performed only during system heatup and cooldown operations with no fuel in the reactor vessel. This SR refers to Figure 3.4.3-2 which provides applicable heatup and cooldown limitations, including reactor coolant pump (RCP) operating restrictions and allowable heatup and cooldown rates. These curves are used during inservice hydrostatic testing that is performed in a defueled condition. The Notes on Figure 3.4.3-1 and Figure 3.4.3-2 are applicable to heatups and cooldowns performed within these limits.

SR 3.4.3.4 is modified by a Note that requires this SR to be performed only during PHYSICS TESTS with the average RCS temperature ≤ 525°F. This SR refers to Figure 3.4.3-1 which provides applicable limitations under which the unit may be critical, including Reactor Coolant Pump (RCP) operating restrictions and allowable heatup rates. This curve is used during PHYSICS TESTING. This is because LCO 3.4.2, "RCS Minimum Temperature for Criticality," normally limits the temperature for criticality to well above this curve. However, an exception to LCO 3.4.2 is provided by LCO 3.1.9, "PHYSICS TEST Exceptions - MODE 2," during PHYSICS TESTS initiated in MODE 2.

When the decay heat removal (DHR) system is operating with no RCPs operating, the indicated DHR system return temperature to the reactor vessel is the appropriate temperature indicator.

REFERENCES

1. BAW-10046A, "Methods of Compliance with Fracture Toughness and Operational Requirements of 10CFR50, Appendix G", Rev. 2, June 1986.

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. FTI Document 77-1258569-01.

6. BAW-1543, Integrated Reactor Vessel Material Surveillance Program (latest revision).

7. BAW-2121P, Irradiation Induced Reduction in Charpy Upper Shelf Energy of Reactor Vessel Welds.

8. FTI Calculations 32-1245917-00 and 32-1257716-00.
9. 10 CFR 50, Appendix H.

10. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

11. 10 CFR 50.36.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the reactor coolant 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 reactor coolant 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 only two or three pumps in operation the reactor power level is restricted to a nominal 49% RTP or 75% RTP, respectively, 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) Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip setpoint is automatically reduced when a pump is taken out of service. Manual resetting is not necessary.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 1) 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 RCS flow on DNB. The initial condition DNB protection for the limiting loss of coolant flow event for four, three, and two pump operation is provided by the RCS flow surveillance criteria specified in the COLR for SR 3.4.1.3 and SR 3.4.1.4. The loss of coolant flow event which has been found to produce the limiting DNB is the four-to-two pump coastdown. In addition to the coastdown events, the single pump locked rotor event has been analyzed and shows that either the minimum DNB ratio is not less than the applicable critical heat flux correlation limit, or fuel cladding was shown to experience no significant temperature excursions.

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 112% RTP. This is the design overpower condition for four pump operation. The 112% value is the accident analysis limit 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 that protects 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 nuclear overpower RCS flow and measured AXIAL POWER IMBALANCE Function. The maximum power level for three pump operation is identified in the COLR 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, design evaluation (including analyses at steady state, ECCS initial conditions, and DNB conditions) also shows 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 restricted to 24 hours (Ref. 2) since not all transient and accident conditions have been analyzed.

RCS Loops-MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36 (Ref. 3).

LCO

The purpose of this LCO is to require adequate forced flow for core heat removal via two RCS loops. An operating loop consists of at least one operating RCP and a SG capable of heat removal. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power; if fewer pumps are available, power must be reduced as specified in the COLR.

APPLICABILITY

In MODES 1 and 2, the reactor may be 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" (MODE 6); and
- LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

With one RCP not in operation in each loop, the assumptions of the safety analyses are not met, but design evaluation provided in Reference 2 concludes that events initiated during two pump operation would be expected to respond within the acceptance criteria for the ECCS. However, since no analysis was performed, Technical Specifications for two pump operation will only allow operation in MODES 1 or 2 for a period not to exceed 24 hours. The Completion Time of 18 hours provides sufficient time to restore operation of an additional RCP, while allowing time to place the unit in MODE 3 within the 24 hour limitation if restoration of a third RCP is not accomplished.

ACTIONS (continued)

B.1

If the Required Action and associated Completion Time of Condition A are not met, or if the LCO is not met for any reason other than provided in Condition A, the unit must be placed in a MODE in which the requirements are not applicable. This is accomplished by placing the unit in MODE 3. This 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 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 helps 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. SAR, Chapters 14 and 3A.

2. BAW-10103A, Revision 3, July 1977.

3. 10 CFR 50.36.

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 the intent of this LCO is to provide forced flow from at least one RCP for core heat removal and transport. The flow provided by one RCP is adequate for heat removal and for boron mixing. However, two RCS loops are required to be OPERABLE to provide redundant paths for heat removal.

Reactor coolant natural circulation is not normally used. 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. Boron reduction in natural circulation is prohibited because mixing to obtain a homogeneous concentration in all portions of the RCS cannot be ensured.

APPLICABLE SAFETY ANALYSES

No safety analyses 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 4 of 10 CFR 50.36 (Ref. 1).

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 preferred way to transport heat, although natural circulation flow is also acceptable under certain conditions. A minimum of one running RCP meets the LCO requirement for one loop in operation.

The Note permits a limited period of operation without RCPs. All RCPs may be removed from operation of ≤ 8 hours per 24 hour period for the transition to or from the Decay Heat Removal (DHR) System, and otherwise may be removed from operation for ≤ 1 hour per 8 hour period. During this condition, boron reduction with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, is prohibited because an even concentration distribution throughout the RCS cannot be ensured. Core outlet temperature is to be maintained at least 10°F below the saturation temperature so that: a) no vapor bubble may form and possibly cause a natural circulation flow obstruction; and b) pump restart criteria (which vary with pressure) are met.

In MODES 3, 4, and 5, it is sometimes necessary to stop all RCP or DHR pump forced circulation (e.g., change operation from one DHR train to the other, to perform surveillance or startup testing, to perform the transition to and from DHR System cooling, or to avoid operation below the RCP minimum net positive suction head limit). This is acceptable because the reactor coolant temperature can be maintained subcooled and boron stratification affecting reactivity control is not expected.

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is OPERABLE. To be considered OPERABLE, an RCP must be capable of being powered and able to provide forced flow if required. Similarly, an SG must be capable of transferring heat from the reactor coolant at a controlled rate.

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";

APPLICABILITY (continued)

- 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" (MODE 6); and
- LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

If one RCS loop is inoperable, redundancy for forced 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.

B.1

If the Required Action and associated Completion Time of Condition A are not met, the unit must be brought to MODE 4. In MODE 4, the unit 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 unit conditions and without challenging unit systems.

C.1 and C.2

If no RCS loop is OPERABLE or a required RCS loop is not in operation, (no RCS loop is required to be in operation provided the conditions of the Note in the LCO section are met), 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 operation and to OPERABLE status. 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 operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loop (and pump) is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced 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

Verification that each required RCP is OPERABLE ensures that an 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 that is not in operation. 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. 10 CFR 50.36.

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 coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RCP or one DHR pump for decay heat removal and transport. The flow provided by one RCP or 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.

APPLICABLE SAFETY ANALYSES

No safety analyses are performed with initial conditions in MODE 4.

RCS Loops-MODE 4 satisfies Criterion 4 of 10 CFR 50.36 (Ref. 1).

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 circulation. The second loop that is required to be OPERABLE provides redundant paths for heat removal.

The Note permits a limited period of operation with the normally required RCP or DHR pump removed from operation. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained below saturation temperature by $\geq$ 10°F so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

LCO (continued)

When the DHR pumps are stopped, no alternate heat removal path exists, unless the RCS and SGs have been placed in service in forced or natural circulation. The response of the RCS without heat removal through the DHR System or the SGs depends on the core decay heat load and the length of time that the DHR pumps are stopped. As decay heat diminishes, the effects on RCS temperature and pressure diminish. Without cooling by DHR, if the SGs are not capable of removing heat, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (pressure and temperature (P/T) or low temperature overpressure protection (LTOP) limits) must be observed and forced DHR flow or heat removal via the SGs must be re-established prior to reaching the pressure limit.

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an OPERABLE SG. To be considered OPERABLE, an SG must be capable of transferring heat from the reactor coolant at a controlled rate.

Similarly for the DHR System, an OPERABLE DHR loop is comprised of the OPERABLE DHR pump(s) capable of circulating RCS fluid through the DHR heat exchanger(s) and back to the RCS. To be considered OPERABLE, a DHR pump must be capable of being powered and able to provide flow if required, and a DHR heat exchanger must be capable of transferring heat from the reactor coolant at a controlled rate.

A DHR loop may be considered OPERABLE during alignment and when aligned for low pressure injection if it is capable of being manually (locally or remotely) realigned to the DHR mode of operation and is not otherwise inoperable. This provision arises because of the dual requirements of the components that comprise the low pressure injection/decay heat removal system.

APPLICABILITY

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

Operation in other MODES is covered by:

- LCO 3.4.4, "RCS Loops-MODES 1 and 2";
- LCO 3.4.5, "RCS Loops-MODE 3";
- LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";

APPLICABILITY (continued)

- 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" (MODE 6); and
- LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

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 unit 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 restoration of a DHR loop, rather than a cooldown of extended duration.

B.1 and B.2

If no RCS or DHR loops are OPERABLE or a required loop is not in operation (no loop is required to be in operation provided the conditions of the Note in the LCO section are met), 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 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

ACTIONS (continued)

B.1 and B.2 (continued)

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 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 flow is providing decay heat removal. Verification includes flow rate, temperature, or pump status monitoring. 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

Verification that each required pump is OPERABLE ensures that an 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

1. 10 CFR 50.36.

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 service water via the decay heat removal (DHR) heat exchangers. 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 do not typically 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. The intent of this LCO is to provide forced flow from at least one DHR loop for decay heat removal and transport. The flow provided by one DHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide a backup method for heat removal.

APPLICABLE SAFETY ANALYSES

No safety analyses are performed with initial conditions in MODE 5.

RCS Loops-MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36 (Ref. 1).

LCO

The purpose of this LCO is to require that at least one of the DHR loops be OPERABLE and in operation with an additional DHR loop OPERABLE or both SGs with secondary side water level ≥ 20 inches. One DHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. The second DHR loop is normally maintained as a backup to the operating DHR loop to provide redundancy for decay heat removal. However, if the standby DHR loop is not OPERABLE, a sufficient alternate method of providing redundant heat removal paths is to provide both SGs with their secondary side water levels ≥ 20 inches. Should the operating DHR loop fail, the SGs could be used to remove the decay heat.

LCO (continued)

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 SG(s) can be used as a heat sink, a motor driven feedwater pump is needed, because it is independent of steam. Condensate pumps, the auxiliary feedwater pump, or the motor driven emergency 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 should be accessible from the feedwater pumps so that natural circulation can be stimulated. The SGs are primarily a backup to the DHR pumps, which are used for forced flow. By requiring the SGs to be a backup heat removal path, the option to increase RCS pressure and temperature for heat removal in MODE 4 is provided.

Note 1 permits the DHR pumps to be stopped for up to 1 hour. The circumstances for stopping both DHR trains 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; and (b) no operations are in process that would cause reduction of the RCS boron concentration.

The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained when DHR forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained below saturation temperature by ≥ 10°F so that no vapor bubble would form and possibly cause a natural circulation flow obstruction. In this MODE, the steam generators are used as a backup for decay heat removal and, to ensure their availability, the RCS loop flow path is to be maintained with subcooled liquid.

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

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

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

LCO (continued)

A DHR loop may be considered OPERABLE during alignment and when aligned for low pressure injection if it is capable of being manually (locally or remotely) realigned to the DHR mode of operation and is not otherwise inoperable. This provision arises because of the dual requirements of the components that comprise the low pressure injection/decay heat removal system.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump and an OPERABLE DHR heat exchanger.

To be considered OPERABLE, DHR pumps must be capable of being powered and are able to provide flow if required. During performance of SR 3.8.1.7 or SR 3.8.1.8, the affected DHR pump may be considered OPERABLE even with the breaker "racked down" since placing this second pump in operation is a manual action. Similarly, an OPERABLE SG can perform as a heat sink when it has an adequate water level.

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" (MODE 6); and
- LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1, A.2, B.1, and B.2

If one required DHR loop is inoperable and any required SG has secondary side water level < 20 inches, redundancy for heat removal is lost. Action must be initiated to restore a second DHR loop to OPERABLE status or initiate action to restore the secondary side water level in the SG(s), and action must be taken immediately. Either Required Action will restore redundant decay heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

C.1 and C.2

If no required DHR loop is in operation, except as provided in Note 1, or no required DHR 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 DHR loop to OPERABLE status and operation must be initiated. The 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 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 operation for decay heat removal

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SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required DHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. 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 SGs are OPERABLE by ensuring their secondary side water levels are ≥ 20 inches ensures that redundant heat removal paths are available if the second DHR loop is not OPERABLE. 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 RCS loop status.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that each required DHR pump is OPERABLE ensures that a DHR loop can be placed in operation if needed to maintain decay heat removal and reactor coolant circulation. If the secondary side water level is ≥ 20 inches in 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

1. 10 CFR 50.36.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with loops not filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the decay heat removal (DHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

Loops are considered not filled when the RCS draining is initiated (as might be the case for refueling or maintenance). Additionally, reductions of RCS inventory below el. 375 ft. are termed reduced inventory operations. 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.

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 require forced flow from at least one DHR pump for decay heat removal and transport, and 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.

RCS Loops-MODE 5 (Loops Not Filled) satisfies Criterion 4 of 10 CFR 50.36 (Ref. 2)

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.

Note 1 permits the DHR pumps to be de-energized for ≤ 1 hour. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained or draining operations when DHR forced flow is stopped.

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 MODE 5 when these tests are safe and possible.

A DHR loop may be considered OPERABLE during alignment and when aligned for low pressure injection if it is capable of being manually (locally or remotely) realigned to the DHR mode of operation and is not otherwise inoperable. This provision arises because of the dual requirements of the components that comprise the low pressure injection/decay heat removal system.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump capable of circulating RCS fluid through an OPERABLE DHR heat exchanger and back to the RCS. To be considered OPERABLE, the DHR pumps must be capable of being powered and able to provide flow if required. During performance of SR 3.8.1.7 or SR 3.8.1.8, the affected DHR pump may be considered OPERABLE even with the breaker "racked down" since placing this second pump in operation is a manual action.

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";

APPLICABILITY (continued)

- LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
- LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation-High Water Level" (MODE 6); and
- LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

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.

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

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 Action requires 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 or reduction of RCS water inventory and requires initiation of action to immediately restore one DHR loop to OPERABLE status and operation. The Required Action for restoration does not apply to the condition of both loops not in operation when the exception Note in the LCO is in force. 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 at least one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess RCS loop status.

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 a 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 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.

1. 10 CFR 50.36.

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, the required heaters, and their controls. Pressurizer safety valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves."

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 abnormalities. The water level limit thus serves two purposes:

a. Provides pressure control during normal operation; and

b. Prevents the peak RCS pressure from exceeding the safety limit of 2750 psig during an abnormality.

The maximum water level limit thus permits pressure control equipment to function as designed. The limit preserves the steam space during normal operation, so that both sprays and heaters can operate to maintain the design operating pressure. The level limit also prevents filling the pressurizer (water solid) during abnormalities, thus ensuring that pressure relief devices (electromatic relief valve (ERV) or code safety valves) can control pressure by steam relief rather than water relief. If the level limits were exceeded prior to an abnormality 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 ERV or pressurizer code safety valves.

The minimum water level limit has been established to ensure that water level is above the minimum detectable level.

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

BACKGROUND (continued)

A minimum required available capacity of 126 kW ensures that the RCS pressure can be maintained. Unless adequate heater capacity is available, reactor coolant subcooling may not be maintained (although the pressure control provided by the high head high pressure injection pumps is an alternate method of maintaining subcooling). 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. No safety analyses are performed in lower MODES. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the SAR 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 provided to prevent the peak RCS pressure from exceeding the safety limit of 2750 psig in the event of a rod withdrawal accident or a startup accident. Assuming proper response by reactor protection systems, the level limit prevents water relief through the pressurizer safety valves. If the level limits were exceeded prior to an abnormality that creates a large pressurizer insurge volume leading to water relief, the maximum RCS pressure might exceed the design SL of 2750 psig or damage may occur to the ERV or pressurizer code safety valves. The value for pressurizer level is the safety analysis value. Therefore, the implementing procedures must contain allowances for instrument error.

The requirement for emergency power supplies is based on NUREG-0578 (Ref. 1), item 2.1.1. The intent is to maintain the reactor coolant in a subcooled condition with natural circulation at hot, high pressure conditions for an 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 SAR accident analyses.

In MODES 1 and 2, the maximum pressurizer water level limit satisfies Criterion 2 of 10 CFR 50.36 (Ref. 2). In MODE 3 and MODE 4 above the LTOP enable temperature, the maximum pressurizer water level limit satisfies Criterion 4 of 10 CFR 50.36. 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-0578 (Ref. 1), is the reason for providing an LCO. Therefore, the pressurizer heaters satisfy Criterion 4 of 10 CFR 50.36 (Ref. 2).

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water level ≥ 45 inches and ≤ 320 inches ensures that a steam bubble exists prior to criticality and that the indication of the level is above the minimum detectable level. Limiting the maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires a minimum of 126 kW of pressurizer heaters OPERABLE. To be considered OPERABLE, the required heaters must be powered from an ES bus. This provides assurance that sufficient heater capacity is available to provide RCS pressure control during a loss of off-site power. 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 MODE 3 and, for pressurizer water level, for MODE 4 with RCS temperature > 262°F. The purpose is to prevent water solid RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbations, such as reactor coolant pump startup. The temperature of 262°F has been designated as the cutoff for applicability because LCO 3.4.11, "Low Temperature Overpressure Protection (LTOP)," provides a requirement for pressurizer level at or below 262°F. The LCO does not apply to MODE 5 with loops filled because LCO 3.4.11 applies and provides adequate overpressure protection. This parameter value does not contain allowances for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures. The LCO does not apply to MODES 5 and 6 with partial loop operation.

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. The Applicability is modified by a Note stating that the OPERABILITY requirements on pressurizer heaters do not apply in MODE 4. For MODE 4, 5, or 6, the need to control pressure (by heaters) to ensure loop subcooling for heat transfer is significantly reduced when the Decay Heat Removal System is in service, and therefore the LCO is not applicable.

ACTIONS

A.1

With pressurizer water level outside the limits, 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 limits. The 1 hour Completion Time is considered to be a reasonable time for adjusting pressurizer level.

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. By shutting down the reactor and reducing reactor coolant temperature to at least MODE 3, the potential thermal energy of the reactor coolant mass for mass and energy releases is reduced.

Six hours is a reasonable time based upon operating experience to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Further pressure and temperature reduction to MODE 4 with RCS temperature ≤ 262°F places the unit into a MODE where the LCO is not applicable. The 24 hour Completion Time to reach the nonapplicable MODE is reasonable based upon operating experience.

C.1

If the required 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 non-ES bus powered heaters.

D.1 and D.2

If the Required Action and associated Completion Time are 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 MODE 3 within 6 hours and to MODE 4 within the following 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that pressurizer water level is maintained below the upper limit to provide a minimum space for a steam bubble. The values specified for pressurizer level do not contain an allowance for instrument error. Therefore, additional allowances for instrument uncertainties must be provided in the implementing procedures. 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.

SR 3.4.9.2

The SR requires sufficient pressurizer heaters which are connected to an ES bus verified to be capable of providing the required capacity. (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 18 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," July 1979.

2. 10 CFR 50.36.

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 (Ref. 1). 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. One safety valve is required for MODE 3 and portions of MODE 4. For the remainder of MODE 4, MODE 5, and MODE 6 with the reactor head on, overpressure protection is provided by operating procedures and LCO 3.4.11, "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. 2). The required lift pressure is 2500 psig + 1%, - 3%. The safety valves discharge steam from the pressurizer to a quench tank located in the reactor building. The discharge flow is indicated by acoustic flow monitoring devices, by an increase in temperature downstream of the safety valves, and by an increase in the quench tank temperature, pressure, and level.

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

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

APPLICABLE SAFETY ANALYSES

The overpressure protection analysis (Ref. 3) is 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%). One pressurizer code safety valve is capable of preventing overpressurization in MODE 3 and in MODE 4 with RCS temperature > 262°F since its relieving capacity is greater than that required by the sum of the available heat sources, i.e., pump energy, pressurizer heaters, and reactor decay heat (Ref. 1 and 4). These valves must accommodate pressurizer insurges that

APPLICABLE SAFETY ANALYSES (continued)

could occur during a startup, rod withdrawal, or ejected rod event. The startup accident establishes the minimum safety valve capacity. The startup accident is assumed to occur at low power. Single failure of a safety valve is neither assumed in the accident analysis nor required to be addressed by the ASME Code. Compliance with this Specification is required to ensure that the accident analysis and design basis calculations remain valid.

In MODES 1 and 2, pressurizer safety valves satisfy Criterion 3 of the 10 CFR 50.36 (Ref. 5). In MODE 3 and MODE 4 above the LTOP enable temperature, the pressurizer safety valves satisfy Criterion 4 of 10 CFR 50.36.

LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psig) and within the specified tolerance to avoid exceeding the maximum RCS design pressure SL, to maintain accident analysis assumptions and to comply with ASME Code requirements. The upper and lower as-left pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 2) 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.

The LCO is modified by four Notes. Note 1 states that in MODE 3 and MODE 4 with RCS temperature above 262°F, only one pressurizer safety valve is required to be OPERABLE. In this condition, one pressurizer safety valve is capable of preventing overpressurization when the reactor is not critical since its relieving capacity is greater than the sum of the available heat sources.

Note 2 allows entry into MODE 3, and into MODE 4 with RCS temperature > 262°F, with the lift settings potentially outside the limits. This permits testing of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 36 hour exception is based on an 18 hour outage time for each of the two valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

LCO (continued)

Note 3 states that the LCO is not applicable in MODE 3, and in MODE 4 with RCS temperature > 262°F during hydrostatic tests in accordance with ASME Boiler and Pressure Vessel Code, Section III. During hydrostatic tests, the code safeties must be gagged to prevent them from relieving at the target test pressure. RCS pressure is carefully observed and compensatory measures are in place to provide assurance that the pressure is appropriately controlled during the performance of hydrostatic tests.

Note 4 states that the provisions of LCO 3.0.3 are not applicable in MODE 3, and in MODE 4 with RCS temperature > 262°F. In the event no code safety valve is OPERABLE in this MODE, the Required Actions ensure that the RCS is placed in a condition in which the ERV is capable of relieving any potential LTOP pressure transient.

The parameter value (262°F) does not contain allowances for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP enable temperature, OPERABILITY of pressurizer safety valve(s) is required to ensure adequate relieving capacity is available to keep reactor coolant pressure below 110% of its design value during certain accidents.

The LCO is not applicable in MODE 4 with RCS temperature ≤ 262°F, in MODE 5, nor in MODE 6 when the reactor vessel head is on because LTOP protection is provided. Overpressure protection is not required in MODE 6 with the reactor vessel head removed.

The parameter value (262°F) does not contain allowances for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures.

ACTIONS

A.1

With one pressurizer safety valve inoperable in MODES 1 and 2, 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.

ACTIONS (continued)

B.1

If the Required Action and associated Completion Time of Condition A are not met, or if both pressurizer safety valves are inoperable in MODES 1 and 2, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 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 unit systems. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

C.1

With the required pressurizer code safety valve inoperable, the RCS overpressure protection capability is significantly reduced and an overpressure event could challenge the integrity of the RCPB. Therefore, the unit must be placed in a condition in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 4 with RCS temperature at or below the LTOP enable temperature within 18 hours. The 18 hours allowed is reasonable, based on operating experience, to reach a low temperature within MODE 4 without challenging unit systems. With RCS temperature at or below 262°F, overpressure protection is provided by LTOP.

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 Section XI of the ASME Code (Ref. 6), which provides the activities and the Frequency necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is + 1%, - 3% for OPERABILITY (Ref. 7); however, the valves are reset to ± 1% during the Surveillance to allow for drift.

REFERENCES

1. SAR, Section 4.2.4.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article 9, Summer 1968.

3. SAR, Section 4.3.8.

4. SAR, Section 4.3.11.4.

5. 10 CFR 50.36.

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

7. ASME/ANSI, Operations and Maintenance Codes (OM), Part 10, 1987, Part 10 Addenda, 1988, and Part 1, 1987.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP controls prevent RCS overpressure 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) as modified by approved exemptions. The reactor vessel is the limiting RCPB component requiring such protection. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," provides the allowable combinations for 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 may 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 and a minimum coolant addition capability. The pressure relief capacity requires the (power operated) electromatic relief valve (ERV) to be OPERABLE with the lift setpoint reduced and pressurizer coolant level at or below a maximum limit for the RCS pressure, or the RCS depressurized and with an RCS vent of sufficient size to handle the limiting LTOP transient.

The LTOP approach to protecting the vessel by limiting coolant addition capability requires deactivating HPI, and isolating the core flood tanks (CFTs).
Should an HPI pump inject on an HPI actuation, the pressurizer level and ERV or another RCS vent may not prevent overpressurizing the RCS. As indicated in Reference 3, the deactivation of HPI injection capability, along with the LTOP alarms, provides sufficient basis for excluding the inadvertent actuation of HPI as a design basis event. Additionally, the CFT controls preclude the inadvertent mass input from the CFT. Finally, maintaining the pressurizer level to prevent operation in a water solid condition with the RCS pressure boundary intact provides a compressible vapor space or cushion (either steam or nitrogen) that can

BACKGROUND (continued)

accommodate a coolant insurge and prevent a rapid pressure increase, allowing the operator time to stop the increase. The ERV, with reduced lift setting, or the RCS vent is the overpressure protection device that acts as backup to the operator in terminating an increasing pressure event.

With HPI deactivated, the ability to provide RCS coolant addition is restricted. To allow for coolant addition, the LCO does not require the makeup function to be deactivated. Due to the lower pressures associated with the LTOP MODES and the expected decay heat levels, the makeup function can provide flow through the makeup control valve.

ERV Requirements

As designed for the LTOP, the ERV is signaled to open if the RCS pressure reaches a limit set in the LTOP actuation circuit. The LTOP actuation circuit monitors RCS pressure and determines when an overpressure condition is approached. When the monitored pressure meets or exceeds the setting, the ERV is signaled to open. Maintaining the lowered setpoint ensures the Reference 1 limits will be met in any event analyzed for LTOP.

RCS Vent Requirements

Once the RCS is depressurized, adequate pressure relief capability may be provided by a vent path to the reactor building atmosphere which is capable of relieving the flow of the limiting LTOP transient and maintaining pressure below P/T limits. The required vent capacity may be provided by one or more vent paths. Acceptable RCS vent paths include any of the following: removing a pressurizer safety valve, locking the ERV in the open position and disabling its block valve in the open position, or similarly establishing a vent by removing a steam generator (SG) primary manway, removing a SG primary hand hole cover, removing all control rod drive top closure assemblies (excluding reactor vessel level probe), or removing a pressurizer manway. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Refs. 4, 5, 6, and 7) demonstrate that the reactor vessel can be adequately protected against overpressurization transients during shutdown. The pressure and temperature limits are derived from fracture mechanics analyses. Transients are then evaluated to determine a required ERV setpoint and other unit conditions that will ensure that the P/T limits are not exceeded.

Fracture mechanics analyses (using the safety margins of Reference 8) established the temperature of LTOP Applicability at 262°F. Above this temperature, the pressurizer safety valves provide the reactor vessel overpressure protection. The actual temperature at which the allowable pressure falls below the pressurizer.

APPLICABLE SAFETY ANALYSES (continued)

safety valve setpoint increases as vessel material ductility decreases due to neutron embrittlement. P/T limits are periodically determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3 discuss these examinations. For the current limits, vessel materials are assumed to have a neutron irradiation accumulation equivalent to 31 effective full power years (EFPYs) of operation. Each time the P/T limit curves are revised, the LTOP is re-evaluated to ensure that its functional requirements can still be met. The ERV setpoint is revised if necessary.

Transients that are capable of overpressurizing the RCS at low temperature result in either excessive mass input or excessive heat input. Such transients include: HPI actuation, CFT discharge, energization of the pressurizer heaters, failing the makeup control valve open, loss of decay heat removal, starting a reactor coolant pump (RCP) with a large temperature mismatch between the primary and secondary coolant systems, and addition of nitrogen to the pressurizer. Without controls, HPI actuation and CFT discharge would be transients that result in exceeding P/T limits within the 10 minute period in which time no operator action can be assumed to take place. For the remaining events, operator action after that time precludes overpressurization.

This specification prevents exceeding the P/T limits by: 1) limiting the capability for rapid mass input to the RCS; and 2) ensuring that adequate vent capability exists to accommodate inadvertent mass or energy addition to the RCS. Pressurizer level is also limited to ensure that increasing pressure during a transient will be slow enough to preclude exceeding pressure limits within the 10 minutes assumed to be required for operator action to mitigate the transient. Mass input into the system is limited by disabling HPI (with specific exceptions) and by deactivating pressurized CFT discharge isolation valves in the closed position with their power breakers open (with specific exceptions). The analyses demonstrate that HPI transients involving one HPI pump can be accommodated by the ERV without exceeding the maximum allowable pressure.

The ERV setpoint is determined by modeling LTOP performance assuming the most limiting LTOP transient of a makeup control valve failing open. Pressure overshoot beyond the setpoint resulting from signal processing and valve stroke times is considered. The resulting ERV setpoint ensures the reference 1 limits will not be exceeded.

Vent capability is required to ensure that the maximum allowable pressure is not exceeded in the event of full opening of the makeup control valve while one makeup pump is running. Acceptable vent paths have adequate capacity at a system pressure of 100 psig which is less than the maximum RCS pressure on the P/T limit curve in LCO 3.4.3.

APPLICABLE SAFETY ANALYSES (continued)

The ERV is an active component. Therefore, its failure represents the worst case single active failure of LTOP features. The other vent paths are passive and not subject to active failure.

The LTOP satisfies Criterion 2 of 10 CFR 50.36 (Ref. 9).

LCO

The LCO requires an LTOP system OPERABLE with a limited coolant input capability and a pressure relief capability. To limit coolant input, the LCO requires the HPI deactivated, and the CFT discharge isolation valves closed and deactivated. For pressure relief, the LCO requires the pressurizer coolant level to be below a level which represents a water solid condition, and the ERV OPERABLE with a lowered lift setting or the RCS depressurized and a vent established.

HPI deactivation requires that the HPI system be incapable of causing a significant increase in RCS pressure (motor operated valves de-activated closed, HPI pump breakers racked down, or other configurations that prevent inadvertent HPI actuation). CFT isolation requires the CFT discharge valves to be closed and the circuit breakers for the motor operators to be opened.

The HPI deactivation and CFT isolation requirements are modified by five Notes. Note 1 indicates that the requirements are not applicable during ASME Section XI testing. This exception provides for required testing during these shutdown conditions rather than at power when the HPI and CFTs are required to be OPERABLE for the ECCS function. Note 2 indicates that the requirements are not applicable for the HPI deactivation during fill and vent of the RCS. The HPI pumps are used for this normal makeup function and must be available. Specific procedural controls are provided to prevent overpressurization during this activity. Note 3 indicates that the requirements are not applicable for the HPI deactivation during emergency RCS makeup. This exception is necessary to enhance the response capability to a loss of decay heat removal event without violating the TS (Ref. 10). Note 4 indicates that the requirements are not applicable for the HPI deactivation during valve maintenance. This exception allows maintenance to be performed during these shutdown conditions rather than at power when the HPI is required to be OPERABLE for the ECCS function. Note 5 states that CFT isolation is only required when CFT pressure is more than or equal to the maximum RCS pressure for the existing RCS temperature, as allowed in LCO 3.4.3. This is acceptable since the CFT can not be the source of an overpressurization event when its pressure is less than the allowable RCS pressure.

The pressurizer is considered to represent a water solid condition when coolant level is > 105 inches, when RCS pressure is > 100 psig, or > 150 inches, when RCS pressure is ≤ 100 psig. Although a vapor space still exists with pressurizer level above these values, from an analytical point of view, the unit is considered to be water solid. These parameter values contain allowances for instrument error.

LCO (continued)

The pressurizer level requirements are modified by two Notes. Note 1 indicates that the requirements are not applicable during operation allowed by the Emergency Operating Procedures (EOPs). This exception provides for use of the “feed and bleed” process when necessary as determined by the EOPs. Note 2 indicates that the requirements are not applicable during RCS hydrotesting. Specific procedural controls are provided to prevent overpressurization during this activity.

OPERABLE pressure relief capability may be provided by an OPERABLE ERV, or by depressurizing the RCS and providing an alternate RCS vent path. For the ERV to be considered OPERABLE, its block valve must be open, its lift setpoint must be set at ≤ 460 psig, testing must have proven its ability to open at that setpoint, and motive power must be available to the ERV and its control circuits. With the RCS depressurized, acceptable alternate vent paths include removing a pressurizer safety valve, locking the ERV in the open position and disabling its block valve in the open position, removing a SG primary manway, removing a SG primary hand hole cover, removing all control rod drive top closure assemblies (excluding reactor vessel level probe), or removing a pressurizer manway.

APPLICABILITY

This LCO is applicable in MODE 4 with RCS temperature ≤ 262°F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The Applicability temperature of 262°F is established by fracture mechanics analyses. The pressurizer safety valves provide overpressure protection to meet LCO 3.4.3 P/T limits above 262°F. 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, and MODE 4 above 262°F.

The parameter value (262°F) does not contain allowances for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures.

ACTIONS

A.1, B.1, and B.2

With the pressurizer level not within its required limits, the time for operator action in a pressure increasing event is reduced. The postulated event most affected in the LTOP MODES is failure of the makeup control valve, which fills the pressurizer relatively rapidly. Restoration is required within 1 hour.

ACTIONS (continued)

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

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

The Completion Times again are based on operating experience that these activities can be accomplished in these time periods and that a limiting LTOP transient is not likely in the allowed times.

C.1 and D.1

With the required ERV inoperable, overpressure relieving capability is lost, and restoration of the ERV within 1 hour is required. If that cannot be accomplished, the ability of the Makeup System to add water must be limited within the next 12 hours.

If restoration cannot be completed within 1 hour, Required Action D.1 must be performed to limit RCS water addition capability. Makeup is not deactivated to maintain the RCS coolant level. Required Action D.1 requires reducing the makeup tank level to ≤ 73 inches. This makes the available makeup water volume insufficient to exceed the LTOP limit by a makeup control valve full opening (Ref. 3). This parameter value does contain allowances for instrument error. No additional allowances for instrument error are required in the implementing procedures.

These Completion Times also consider these activities can be accomplished in these time periods. A limiting LTOP event is not likely in those times.

Some ERV testing or maintenance can only be performed at unit shutdown. Such activity is permitted if Required Action D.1 is taken to compensate for required ERV unavailability.

E.1

With the LTOP requirements not met for any reason other than cited in Condition A through D, action must be initiated to restore compliance immediately. The immediate Completion Time reflects the urgency of quickly proceeding with the Required Actions.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Verification of the pressurizer level at ≤ 105 inches when RCS pressure is > 100 psig or ≤ 150 inches when RCS pressure is ≤ 100 psig, by observing control room or other indications ensures that the unit is not in a water solid condition and that a cushion of sufficient size is available to reduce the rate of pressure increase from potential transients (Ref. 3).

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

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

SR 3.4.11.2 and SR 3.4.11.3

Verifications must be performed that the HPI is deactivated, and each pressurized CFT is isolated. These Surveillances ensure the minimum coolant input capability will not create an RCS overpressure condition to challenge the LTOP. The Surveillances are required at 12 hour intervals.

The 12 hour intervals are shown by operating practice to be sufficient to assess coolant input capability and verify operation within the safety analysis.

SR 3.4.11.4

OPERABLE pressure relief capability must be provided to prevent overpressurization due to inadvertent full makeup system operation. Such a vent keeps the pressure from full makeup flow within the LCO limit. OPERABLE pressure relief capability may be provided by an OPERABLE ERV, or by depressurizing the RCS and providing an alternate RCS vent path.

For the ERV to be considered OPERABLE, its block valve must be open, its lift setpoint must be set at ≤ 460 psig, testing must have proven its ability to open at that setpoint, and motive power must be available to the two valves and their control circuits. The parameter value of 460 psig does not contain allowances for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.4 (continued)

With the RCS depressurized, acceptable alternate vent paths include: a) removing a pressurizer safety valve; b) locking the ERV in the open position and disabling its block valve in the open position; c) removing a SG primary manway; c) removing a SG primary hand hole cover; d) removing all control rod drive top closure assemblies (excluding reactor vessel level probe); and e) removing a pressurizer manway.

For a vent path not locked open, the Frequency is every 12 hours. For a locked open vent path, the required Frequency is every 31 days.

The Frequency intervals are considered adequate based on operating practice to determine adequacy of pressure relief capability and verify operation within the safety analysis.

SR 3.4.11.5

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

The 18 month Frequency considers a typical refueling cycle and industry accepted practice.

REFERENCES

1. 10 CFR 50, Appendix G.

2. Generic Letter 88-11.

3. ANO-1 LTOP Safety Evaluation Report (1CNA058302) dated May 5, 1983.

4. Response to NRC Request for Additional Information (1CAN117608) dated November 15, 1976.

5. Response to NRC Request for Additional Information (1CAN127602) dated December 3, 1976.

6. Response to NRC Request for Additional Information (1CAN037716) dated March 24, 1977.

REFERENCES (continued)

7. ANO-1 License Amendment Request (1CAN119608), dated November 26, 1988, and Operating License Amendment 188, (1CNA039703) dated March 14, 1997.

8. ANO-1 Request for Exemption (1CAN119608), dated November 26, 1996, and Exemption from Requirements of 10 CFR 50.60, (1CNA039702) dated March 12, 1997.

9. 10 CFR 50.36.

10. ANO-1 License Amendment Request (1CAN059008), dated May 22, 1990, and Operating License Amendment 138, (1CNA119002) dated November 1, 1990.

B 3.4 REACTOR COOLANT SYSTEM

B 3.4.12 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 total 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.

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 thyroid dose conversion factors used in the calculation of DOSE EQUIVALENT I-131 are identified in Section 1.1, “Definitions.”

Rupture of a steam generator tube would allow primary coolant activity to enter the secondary coolant. The major portion of this activity is noble gases and would be released to the atmosphere from the condenser vacuum pump or a relief valve. Activity would continue to be released until the operator could reduce the primary system pressure below the setpoint of the secondary relief valves and could isolate the faulty steam generator. The worst credible set of circumstances is considered to be a double-ended break of a single steam generator tube, followed by isolation of the faulty steam generator within 34 minutes after the tube break. Assuming the full differential pressure across the steam generator, no more than one-quarter of the total primary coolant could be released to the secondary coolant in this period. The decay heat during this period of 1 hour for pressure reduction will generate steam in the secondary system representing less than 15 weight percent of the secondary system.

The parameters assumed in the dose analysis (Ref. 2) for the single steam generator tube failure included the following values:

APPLICABLE SAFETY ANALYSES (continued)

1. total primary coolant volume (mass) = 5.2×10^5 lbs.

2. total secondary coolant volume (mass) = 2×10^6 lbs.

3. leakage rate from primary to secondary system = 1 gpm.

4. fission product decay heat energy for 1 hour = 1.56×10^8 BTU.

5. steam mass released to environs = 2.84×10^5 lbs.

6. primary coolant released to secondary (34 minutes) = 8.7×10^4 lbs.

7. minimum primary to secondary iodine equilibrium activity ratio = 20 to 1 (for 1 gpm leakage).

8. DOSE EQUIVALENT I-131 specific activity = 3.5 µCi/gm (Primary).

9. DOSE EQUIVALENT I-131 specific activity = 0.17 µCi/gm (Secondary).

10. total specific activity in primary = $72/\bar{E}$ µCi/gm.

11. X/Q = 7.0×10^{-4} sec/m^3 at limiting point beyond site boundary of 1046 meters for 30 m release height - equivalent to ground level release due to topography including building wake effect for 5 percentile meteorology.

12. total radioactivity in primary coolant released to secondary coolant released to environs.

13. ten percent of the combined radioiodine activity from primary activity in secondary coolant and secondary activity present in steam mass (released to environs) assumed released to environs.

The whole body dose resulting from immersion in the cloud containing the released activity would include both gamma and beta radiation. The gamma dose is dependent on the finite size and configuration of the cloud. However, the analysis employed the simple model of the semi-infinite cloud, which gives an upper limit to the potential gamma dose. The semi-infinite cloud model is applicable to the beta dose, because of the short range of beta radiation in air. The resulting whole body dose was determined to be less than 0.5 Rem for this accident.

The thyroid dose from the steam generator tube rupture accident has been analyzed assuming a tube rupture at full load and loss of offsite power at the time of the reactor trip, which results in steam release through the relief valves in the period before the faulty steam generator is isolated and primary system pressure is reduced. The limiting iodine activities for the primary and secondary systems are

APPLICABLE SAFETY ANALYSES (continued)

used in the initial conditions. One-tenth of the iodine contained in the liquid which is converted to steam and passed through the relief valves is assumed to reach the site boundary. The resulting thyroid dose from the combined primary and secondary iodine activity released to the environs was determined to be 1.5 Rem for this accident.

The limit for secondary iodine activity is consistent with the limits on primary system iodine activity and primary-to-secondary leakage of 1 gpm. If the activity should exceed the specified limits following a power transient, the major concern would be whether additional fuel defects had developed bringing the total to above expected levels. From the observed removal of excess activity by decay and cleanup, it should be apparent whether activity is returning to a level below the specification limit. Appropriate action to be taken to bring the activity within specification include one or more of the following: gradual decrease in power to a lower base power, increase in letdown flow rate, and venting of the makeup tank gases to the waste gas decay tanks.

The analysis shows the radiological consequences of an SGTR accident are within a small fraction of the Reference 1 dose guideline limits.

RCS Specific Activity satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3).

LCO

The specific iodine activity is limited to $\leq$ 3.5 μCi/gm DOSE EQUIVALENT I-131, and the total specific activity in the primary coolant is limited to the number of μCi/gm equal to 72 divided by $\bar{E}$. The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary during the SGTR will be a small fraction of the allowed thyroid dose. The limit on total specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the SGTR will be a small fraction of the allowed whole body dose.

The analysis shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of 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 $\geq$ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and total specific activity are necessary to limit the potential consequences of an SGTR to within the acceptable site boundary dose values.

APPLICABILITY (continued)

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of an SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the atmospheric dump valves and main steam safety valves.

ACTIONS

A.1

With the specific activity of the reactor coolant greater than the LCO limits, the specific activity must be restored to within limits within 24 hours. The Completion Time of 24 hours is adequate to determine and implement appropriate actions to return specific activity to within limits.

B.1

If the Required Action and associated Completion Time are not met, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. Placing the unit in MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves, and prevents venting the SG to the environment in an SGTR event. The Completion Time of 6 hours is required to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

SR 3.4.12.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once per 7 days. The gross specific activity analysis consists of the quantitative measurement of the total activity of the primary coolant in units of microcuries per gram (μCi/gm). The total primary coolant activity is the sum of the degassed beta-gamma activity and the total of all identified gaseous activities 15 minutes after the primary system is sampled and any identified beta emitters (i.e., tritium, SR89, SR90, etc.). This Surveillance provides an indication of any increase in gross specific activity.

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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.2

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.

SR 3.4.12.3

SR 3.4.12.3 requires radiochemical analysis for $\bar{E}$ determination every 184 days. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the total specific activity LCO limit. The Frequency of 184 days recognizes $\bar{E}$ does not change rapidly.

The radiochemical analysis consists of the quantitative measurement of the activity for each radionuclide which is identified in the primary coolant 15 minutes after the primary system is sampled. The activities for the individual isotopes are used in the determination of $\bar{E}$. The gamma energy per disintegration for those radioisotopes determined to be present shall be as given in "Table of Isotopes" (1967) (Ref. 4) and beta energy per disintegration shall be as given in USNRDL-TR-802 (Part II) (Ref. 5) or other references using the equivalent values for the radioisotopes. Iodine isotopic activities are weighted to give DOSE EQUIVALENT I-131 activity.

This SR is modified by a NOTE that requires the determination be performed within 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. ANO-1 Operating License Amendment 2, (1CNA057502) dated May 9, 1975.

3. 10 CFR 50.36.

4. "Table of Isotopes" (1967).

5. USNRDL-TR-802 (Part II).

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. During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit LEAKAGE from these sources to amounts that do not compromise safe operation. This LCO specifies the types and amounts of allowable LEAKAGE.

SAR Section 1.4, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable criteria for selecting Leakage Detection Systems. Reference 3 provides a comparison of the ANO-1 RCS leak detection systems to Regulatory Guide 1.45 (Ref. 2).

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the reactor building is necessary.

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

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation. The consequences of violating this LCO include increasing the probability of a loss of coolant accident (LOCA). However, the ability to monitor leakage provides advance warning to permit unit shutdown before a LOCA occurs. This advantage has been shown by "leak before break" studies.

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 one gallon per minute or increases to one gallon per minute as a result of accident induced conditions except for the SGTR. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day assures that the conditions assumed in the safety analysis are bounding.

APPLICABLE SAFETY ANALYSES (continued)

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

The SAR (Ref. 4) analysis for SGTR assumes the contaminated secondary fluid is released via turbine bypass valves to the condenser and briefly through the MSSVs to the atmosphere. The 1 gpm primary to secondary LEAKAGE safety analysis assumption is relatively inconsequential compared to the tube rupture leakage.

The safety analysis for the SLB accident assumes 1 gpm primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 100.

RCS leakage detection capabilities and methods are identified and discussed in SAR Section 4.2.3.8 (Ref. 5) and in the Bases for LCO 3.4.15, "RCS Leakage Detection Instrumentation."

In MODES 1 and 2, RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36 (Ref. 6). In MODES 3 and 4, RCS operational LEAKAGE satisfies Criterion 4 of 10 CFR 50.36.

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.

b. <u>Unidentified LEAKAGE</u>

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the reactor building air monitoring and reactor building 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. Controlled reactor coolant pump (RCP) seal leakoff is a normal function and is not considered as LEAKAGE.

LCO (continued)

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 reactor building from specifically known and located sources and LEAKAGE through a SG to the secondary system, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through 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. 7). 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 and to assure the safety analysis is bounding.

APPLICABILITY

In MODES 1, 2, 3, and 4, the LEAKAGE limits are required because the RCS is pressurized and the potential for RCPB LEAKAGE is greatest.

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

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through RCS pressure isolation valves (PIVs) 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 in series leak and result in a loss of coolant mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

If unidentified LEAKAGE, or identified LEAKAGE, or both, are in excess of the LCO limits, the LEAKAGE must be reduced to within limits within 18 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if primary to secondary LEAKAGE is not within limit, or if the Required Action and associated Completion Time of Condition A is not met, 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 unit 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 may be positively identified by inspection. Total LEAKAGE is 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, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows) at or near operating pressure. 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 at or near operating pressure (i.e., at or near 2155 psig). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.1 (continued)

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the systems that monitor the reactor building atmosphere radioactivity and the reactor building 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 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 3.4.16, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 8. 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 RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

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. During normal operation the primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with EPRI Guidelines (Ref. 8).

REFERENCES

1. SAR, Section 1.4, GDC 30.

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

3. Information Submittal - Comparison of ANO-1 RCS Leak Detection Systems to Regulatory Guide 1.45 (1CAN108607), dated October 14, 1986.

4. SAR, Chapter 14.

5. SAR, Section 4.2.3.8.

6. 10 CFR 50.36.

7. NEI 97-06, “Steam Generator Program Guidelines.”

8. 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

RCS pressure isolation valves (PIVs) are identified in Reference 1 as any two normally closed valves in series within the RCS pressure boundary that separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV 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 isolation check valve which is closest to the reactor vessel in the decay heat system injection lines and to each parallel pair of check valves which protect an individual low pressure injection line (Ref. 1). 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. Leakage exceeding the limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading.
PIV leakage could lead to overpressurization of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of the reactor building, an unanalyzed accident that could degrade low pressure injection capability.

The 1975 NRC "Reactor Safety Study" (Ref. 2) identified potential intersystem LOCAs as a significant contributor to the risk of core melt.

A subsequent study (Ref. 3) evaluated various PIV configurations to determine the probability of intersystem LOCAs. In 1981, PIV requirements were issued as an order for modification of the ANO-1 Operating License (Ref. 1).

PIVs are provided to isolate the RCS from the low pressure portion of the Decay Heat Removal (DHR) System.

BACKGROUND (continued)

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

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. Reference 2 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 the reactor building. 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. Overpressurization failure of the DHR low pressure line would result in a LOCA outside the reactor building and subsequent risk of core melt.

Reference 3 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

RCS PIV Leakage satisfies Criterion 4 of the 10 CFR 50.36 (Ref. 4).

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 gpm.

Reference 5 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, the observed rate may be adjusted to account for the maximum pressure differential by assuming leakage is directly proportional to the square root of the pressure differential.

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, 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.

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 reactor building.

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 Required Action may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The leaking flow path must be isolated by two valves. When using this automatic MOV for isolation, deactivation makes the low pressure injection subsystem of one train of the ECCS inoperable since the MOV must automatically open to provide the LPI ECCS function. The ECCS Specification will effectively limit continued operation.

Required Action A.1 requires that the isolation must be performed within 4 hours. Four hours provides time to isolate the affected system and restricts the operation with leaking isolation valves.

B.1

The inoperability of the DHR autoclosure interlock 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 autoclosure interlock is required and inoperable, operation may continue as long as the DHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This action accomplishes the purpose of the autoclosure function.

ACTIONS (continued)

C.1 and C.2

If Required Actions and associated Completion Times are not met, the unit must be brought to a MODE in which the requirement does not apply.

To achieve this status, the unit 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 reactor building. 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 3.4.14.1

Performance of leakage testing on RCS pressure isolation check valve(s) is required to verify that leakage is below the specified limit and to identify leaking valve(s). The leakage limit of 5 gpm maximum applies to each isolation check valve which is closest to the reactor vessel in the DHR System injection lines (DH-14A and DH-14B) and to each parallel pair of check valves which protect an individual low pressure injection line (total for DH-13A and DH-17, and total for DH-13B and DH-18). Leakage testing requires a stable pressure condition. Reference 5 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, the observed rate may be adjusted to account for the maximum pressure differential by assuming leakage is directly proportional to the square root of the pressure differential.

If the in series PIVs are not separately leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant in series valves would be lost.

Testing is to be performed on a Frequency consistent with 10 CFR 50.55a(g) (Ref. 6) as contained in the Inservice Testing Program, and allowed by the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 5). This Frequency 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 unit at power.

The leakage surveillance 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 pressures.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.14.1 (continued)

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.

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 3.4.14.2, SR 3.4.14.3, SR 3.4.14.4, and SR 3.4.14.5

Verifying that the DHR autoclosure interlocks are OPERABLE ensures that RCS pressure will not over pressurize the DHR system. The interlock(s) that prevent the valves from being opened and that close the valves are designed to protect the DHR System from gross overpressurization. Although the specified values include certain process measurement uncertainties, additional allowances for instrument uncertainty are contained in the implementing procedures. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and on the potential for an unplanned transient if the Surveillance was performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

REFERENCES

1. "Order for Modification of License Concerning Primary Coolant System Pressure Isolation Valves," issued April 20, 1981.

2. NUREG-75/014, Reactor Safety Study, Appendix V, October 1975.

3. NUREG-0677, The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes, May 1980.

4. 10 CFR 50.36.

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

6. 10 CFR 50.55a(g).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

SAR, Section 1.4, GDC 30 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable criteria 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 is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can readily be detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The reactor building sump used to collect unidentified LEAKAGE is instrumented to detect increases of 1.0 gpm in the fill rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the reactor building, can 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.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the reactor building. Reactor building temperature and pressure fluctuate slightly during unit operation, but a rise above the normally indicated range of values may indicate RCS LEAKAGE into the reactor building. The relevance of temperature and pressure measurements are affected by reactor building free volume and, for temperature, detector location. Indications from these instruments can be valuable in recognizing rapid and sizable leakage to the reactor building. Temperature and pressure monitors are not required by this LCO.

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. Therefore, the need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the SAR (Ref. 3).

APPLICABLE SAFETY ANALYSES (continued)

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the reactor building are necessary.

In MODES 1 and 2, RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36 (Ref. 4). In MODES 3 and 4, RCS leakage detection instrumentation satisfies Criterion 4 of 10 CFR 50.36.

LCO

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

The LCO requirements are satisfied when monitors of diverse measurement means are available. Thus, the reactor building sump monitor, 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 and pressure are maintained low. Since the temperatures and pressures are lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation is sufficiently smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

The Actions are modified by a Note indicating that the provisions of LCO 3.0.4 do not apply. As a result, a MODE change is allowed when the sump and required radiation monitors are inoperable. This allowance is provided because other instrumentation is available to monitor RCS LEAKAGE.

A.1 and A.2

With the required reactor building sump monitor inoperable, no other form of sampling can provide the equivalent information.

ACTIONS (continued)

A.1 and A.2 (continued)

However, the reactor building atmosphere activity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, performing the periodic surveillance for RCS inventory balance, SR 3.4.13.1, at an increased frequency of 24 hours provides 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, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows) at or near operating pressure. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

Restoration of the required 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 the required gaseous or particulate reactor building atmosphere radioactivity monitoring instrumentation channel inoperable, alternative action is required. Either grab samples of the reactor building 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, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows) at or near operating pressure. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established. The 30 day Completion Time recognizes at least one other form of leak detection is available.

C.1 and C.2

If the Required Action and associated Completion Time are 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 unit systems.

ACTIONS (continued)

D.1

With both required monitors inoperable, no indicated 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 reactor building 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 reactor building atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm function and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

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 the reactor building. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Additionally, operating experience has shown this Frequency is acceptable.

REFERENCES

1. SAR, Section 1.4, GDC 30.
2. Regulatory Guide 1.45, Reactor Coolant Pressure Boundary Leakage Detection Systems, May 1973.
3. SAR, Section 4.2.3.8.
4. 10 CFR 50.36.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 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 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, 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 5.5.9. 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).

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 only briefly released to the atmosphere via safety valves and the majority is discharged to the main condenser.

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 or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, “RCS Specific Activity,” limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. 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 repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair 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 5.5.9, “Steam Generator Program,” 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.

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 significantly affect burst or collapse. In that context, the term "significantly" 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 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 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.

APPLICABILITY (continued)

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 repair criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.16.2. 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 repair 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 refueling outage or SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

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.

ACTIONS (continued)

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 3.4.16.1

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 repair 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 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 3.4.16.1. 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 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.16.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.9 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 repair 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.

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

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 Flood Tanks (CFTs)

BASES

BACKGROUND

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

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

In the refill phase of a 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. Each CFT is piped separately into the reactor vessel downcomer. The CFT injection lines are also utilized by the Low Pressure Injection (LPI) System. Each CFT is isolated from the RCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves are normally open, with power removed from the valve motor to prevent inadvertent closure prior to or during an accident.

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 injected is credited for core cooling.

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

APPLICABLE SAFETY ANALYSES

The CFTs are credited in both the large and small break LOCA analyses at full power (Ref. 1). The CFT line break analysis credits only one CFT, since the tank with the broken line is assumed to empty out the break. These Design Basis Accident (DBA) analyses establish the acceptance limits for the CFTs. In performing the LOCA calculations, conservative assumptions are made concerning the availability of safety injection flow. In addition, a loss of offsite power is considered to ensure worst case conditions are postulated. In the early stages of a limiting large break 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 diesel generators (DGs) start 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. No credit is taken for HPI for large break LOCAs. LPI is not assumed to occur until 35 seconds after the RCS pressure decreases to the ESAS actuation pressure. No operator action is assumed during the blowdown stage of a large break LOCA (Ref. 1).

The small break LOCA analysis also assumes a time delay after ESAS 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 $\leq$ 0.17 times the total cladding thickness before oxidation;

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

d. Core maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

APPLICABLE SAFETY ANALYSES (continued)

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 unit 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 minimum volume requirement for the CFTs ensures that both CFTs can provide adequate inventory to cover the core to the 3/4 point even assuming no liquid remains in the reactor vessel following a LOCA (Ref. 1). The downcomer then remains flooded until the HPI and LPI systems start to deliver flow for limiting large break LOCAs.

The maximum volume limit is based upon the need to maintain adequate gas volume to ensure proper injection and ensure the ability of the CFTs to fully discharge. The limiting safety analysis volume requirement is 1040 ± 70 ft^3. This volume corresponds to CFT levels of ≥ 11.95 ft and ≤ 14.00 ft. These parameter values do not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures.

The minimum nitrogen cover pressure requirement of 560 psig ensures that the contained gas volume will generate discharge flow rates during injection that satisfy the safety analysis. This parameter value does not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures.

The maximum nitrogen cover pressure limit of 640 psig will affect the amount and timing of CFT inventory discharged while the RCS depressurizes. Limiting the maximum pressure will therefore limit the CFT inventory lost through the break and assure that the CFT inventory injected into the RCS at the proper time is bounded by that predicted by the safety analysis. This parameter value does not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures.

The 2270 ppm limit for minimum boron concentration was established to ensure that, following a LOCA with a minimum CFT level, the reactor will remain adequately shutdown in the cold condition following mixing of the CFT and Reactor Coolant System (RCS) water volumes. This parameter value is considered to be a nominal value. No additional allowances for instrument uncertainty are required in the implementing procedures.

In MODE 1, the CFTs satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3). In MODE 2 and MODE 3 with RCS pressure > 800 psig, the CFTs satisfy Criterion 4 of 10 CFR 50.36.

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 with power removed, and the limits established in the SRs 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.

In MODE 3 with RCS pressure ≤ 800 psig, and in MODES 4, 5, and 6, the CFT motor operated isolation valves may be 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.

In addition, LCO 3.4.11, "Low Temperature Overpressure Protection (LTOP)," requires that in MODE 4 when any RCS cold leg temperature is ≤ 262°F, MODE 5, and MODE 6 when the reactor vessel head is on, each CFT whose pressure is greater than or equal to the maximum RCS pressure for the existing RCS temperature allowed by the pressure and temperature limit curves provided in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," be isolated.

ACTIONS

A.1

If the boron concentration of one CFT is not within limits, the 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.

ACTIONS (continued)

B.1

If one CFT is inoperable for a reason other than boron concentration, 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 unit is potentially exposed to a LOCA in these conditions.

C.1 and C.2

If the Required Actions and associated Completion Times of Condition A or B are not met, or if both CFTs are inoperable, 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 RCS pressure reduced to ≤ 800 psig 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 3.5.1.1

Verification every 12 hours that each CFT isolation valve is fully open 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 nature of these parameters, 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.

SURVEILLANCE REQUIREMENTS (continued)

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 nature of this parameter 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 of the affected CFT within 12 hours after a 0.2 ft volume increase will identify whether inleakage from the RCS has caused a reduction in boron concentration to below the required limit. The 0.2 ft increase represents approximately 102 gallons increase in volume. It is not necessary to verify boron concentration if the added water inventory is from a borated water source of known concentration ≥ 2270 ppm, such as the borated water storage tank (BWST), because the water is within CFT boron concentration requirements. Similarly, it would not be necessary to sample the CFT following inventory additions from the CFT makeup tank if sampling has determined that the added inventory had a boron concentration within the CFT requirements. This is consistent with the recommendations of NUREG-1366 (Ref. 4).

SR 3.5.1.5

Removing power from each CFT isolation valve operator ensures that an active failure could not result in the undetected closure of a CFT motor operated isolation valve coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that the power is removed.

REFERENCES

1. SAR, Section 6.1 and 14.2.

2. 10 CFR 50.46.

3. 10 CFR 50.36.

4. NUREG-1366, "Improvements to Technical Specifications Surveillance Requirements," December 1992.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

The ANO-1 SAR states that the High Pressure Injection (HPI), Low Pressure Injection (LPI) and Core Flooding Systems are collectively designed as an Emergency Core Cooling System (ECCS) (Ref. 1). In this Technical Specification, the term ECCS refers to the components associated with the HPI and LPI systems. The core flood tanks are addressed by LCO 3.5.1, "Core Flood Tanks."

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;

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, borated water from the borated water storage tank (BWST) is initially added to the Reactor Coolant System (RCS) via the cold legs and directly to the reactor vessel. After the BWST has been depleted, the recirculation phase is entered as the suction is transferred to the reactor building sump.

Two redundant, 100% capacity trains are provided. In MODES 1 and 2, and MODE 3 with RCS temperature > 350°F, each train consists of high pressure injection (HPI) and low pressure injection (LPI) subsystems. In MODES 1 and 2, and MODE 3 with RCS temperature > 350°F, 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 reactor building sump to the ECCS pumps. 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. Valves are set to balance the HPI flow to the RCS. This flow balance directs sufficient flow to the core to meet the analysis assumptions following a small break LOCA in one of the RCS cold legs.

BACKGROUND (continued)

The HPI pumps are capable of discharging to the RCS at an RCS pressure above the opening setpoint of the pressurizer safety valves. The LPI pumps are capable of discharging to the RCS at pressures below approximately 200 psia. When the BWST has been nearly emptied, the suction for the LPI pumps is manually transferred to the reactor building 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" and enables continued HPI to the RCS, if needed, after the BWST is emptied.

In the long term cooling period, the flowpath inherent in the reactor vessel internals, commonly called the leakage gap flowpath, would be sufficient by itself to preclude boron precipitation (Ref. 2). Flow paths in the LPI System may be procedurally established to preclude the possibility of boric acid in the core region reaching an unacceptably high concentration. The desired flowpath establishes decay heat removal (DHR) in conjunction with LPI cooling. This requires conditions present which allow both DHR pumps to operate simultaneously. If DHR can not be established but hot leg level is above the bottom of the hot leg nozzle, an alternate flowpath is gravity draining from the decay heat suction piping through the idle DHR pump into the reactor building sump. If the first two methods are unsuccessful, the pressurizer auxiliary spray line is used. This provides reverse flow through the core using auxiliary spray into the pressurizer, out the pressurizer into the hot leg via the surge line then reactor vessel into the area above the core.

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 rapidly decrease. The ECCS is actuated upon receipt of an Engineered Safeguards Actuation System (ESAS) signal. If offsite power has not been lost, the safeguard loads start in sequence unless previously operating. If offsite power has been lost, the Engineered Safeguards (ES) buses shed normal operating loads and are connected to the diesel generators. Safeguard loads are then connected in sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the amount of time before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive core flood tanks (CFTs) covered in LCO 3.5.1, "Core Flood Tanks (CFTs)," and the BWST covered in LCO 3.5.4, "Borated Water Storage Tank (BWST)," provide the cooling water necessary to meet 10 CFR 50.46 (Ref. 1 and 3).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 3 and 4), 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 that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

Only the LPI subsystem is assumed to provide injection in the large break LOCA analysis at full power (Ref. 4). This analysis establishes a minimum required flow for the LPI subsystem, as well as the minimum required response time for subsystem actuation. The HPI subsystem is credited in the small break LOCA analysis. This analysis establishes the flow and discharge head requirements for the HPI pump. The SGTR and MSLB analyses also credit the HPI subsystem but are not limiting in HPI subsystem design.

The large break LOCA event assumes a loss of offsite power and a single failure (disabling one ECCS train). For analysis purposes, the loss of offsite power assumption may be conservatively inconsistent with the assumed operation of some equipment, such as reactor coolant pumps (Ref. 4). During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the reactor building. The nuclear reaction is terminated either by moderator voiding during large breaks or CONTROL ROD insertion for small breaks (Ref.4). 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 safety analyses show that an LPI train will deliver sufficient water to match decay heat boiloff rates for a large break LOCA. They also show that the HPI train will deliver sufficient water for a small break LOCA and provide sufficient boron to maintain the core subcritical.

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

APPLICABLE SAFETY ANALYSES (continued)

In the small break LOCA analysis, HPI is not credited until at least 35 seconds after actuation of the ESAS signal. This is based on a loss of offsite power and the associated time delays in startup and loading of the DG.

In MODE 1, the ECCS trains satisfy Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODE 2 and MODE 3 with RCS temperature > 350°F, the ECCS trains satisfy Criterion 4 of 10 CFR 50.36.

LCO

In MODES 1 and 2 and MODE 3 with RCS temperature > 350°F, two independent (and redundant) ECCS trains are required to ensure that at least one is available, assuming a single failure in the other train.

In MODES 1 and 2 and MODE 3 with RCS temperature > 350°F, an ECCS train consists of an HPI subsystem and an LPI subsystem. Each train includes the piping, instruments, pumps, valves, heat exchangers, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon an ESAS signal and the capability to manually transfer suction to the reactor building 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 reactor building sump and to supply borated water to the RCS via two paths (LPI and HPI piggy-back modes).

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

APPLICABILITY

In MODES 1 and 2 and MODE 3 with RCS temperature > 350°F, 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 requirements are based on a small break LOCA.

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, ECCS train OPERABILITY requirements are established by LCO 3.5.3, "ECCS - Shutdown." In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, the probability of an event requiring ECCS actuation is significantly lessened. In this operating condition, the safety injection function is preserved through LCO 3.5.3 requirements for two OPERABLE LPI trains.

APPLICABILITY (continued)

In MODES 5 and 6, unit 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."

ACTIONS

A.1

With one or more trains inoperable, but at least 100% of the injection flow equivalent to a single OPERABLE ECCS train still available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on NRC recommendations (Ref. 6) that are based on a risk evaluation and is a reasonable time for repairs.

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 diverse components, each in a different train, necessarily result in a loss of function for the ECCS. This allows increased flexibility in unit operations under circumstances when diverse components in opposite trains are inoperable, i.e., an HPI subsystem in one train and an LPI subsystem in the opposite train.

An event accompanied by a loss of offsite power and the failure of a DG can disable one ECCS train until power is restored. A reliability analysis (Ref. 6) has shown the risk of having one full ECCS train inoperable to be sufficiently low to justify continued operation for 72 hours.

With one or more components inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A are not met, or one or more components are inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, 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 RCS temperature must be reduced to less than or equal to 350°F 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.

ACTIONS (continued)

C.1

Condition A 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 unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately

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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 Section XI of the ASME Code (Ref. 7). This testing confirms component OPERABILITY, trends performance, and detects incipient failures by indicating abnormal performance. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code.

SR 3.5.2.3

This SR demonstrates that each automatic ECCS valve actuates to the required position on an actual or simulated ESAS signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were performed with the

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3 (continued)

reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the ESAS testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.4

The intent of this SR is to verify that the ECCS pumps are capable of automatically starting on an ESAS signal. Because of the system design configuration and the limitations imposed on pump operation during the unit conditions when this test would be conducted, this verification must be conducted through a series of sequential, overlapping or total steps in order to demonstrate functionality. SR 3.5.2.4 demonstrates that each ECCS pump would be capable of starting by verifying that its breaker closes on receipt of an actual or simulated ESAS signal. SR 3.5.2.4 works in conjunction with the Inservice Testing Program (SR 3.5.2.2) which periodically verifies the ability of the pumps to start and operate within limits, and the ESAS actuation logic testing which periodically verifies the ability of the ESAS to sense, process and generate an actuation signal.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

SR 3.5.2.5

Periodic inspections of the reactor building sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The 18 month Frequency is based on the need to perform this Surveillance during a unit outage. Operating experience has shown this Frequency to be acceptable to detect abnormal degradation.

REFERENCES

1. SAR, Section 6.

2. Letter from A. C. Thadani (NRC) to P. S. Walsh (BWOG) dated March 9, 1993.

3. 10 CFR 50.46.

4. SAR, Section 14.2.2.5.2.

REFERENCES (continued)

5. 10 CFR 50.36.

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

7. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The ANO-1 SAR states that the High Pressure Injection (HPI), Low Pressure Injection (LPI) and Core Flooding Systems are collectively designed as an Emergency Core Cooling System (ECCS) (Ref. 1). In this Technical Specification, the term ECCS refers to the components associated with the LPI system. The HPI system, in conjunction with the LPI system, is covered by LCO 3.5.2, "ECCS-Operating." The core flood tanks are addressed by LCO 3.5.1, "Core Flood Tanks (CFTs)."

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, the required trains consist of two redundant, 100% capacity low pressure injection (LPI) trains.

The LPI flow paths consist of piping, valves, heat exchangers, instruments, controls, and pumps, capable of taking suction from the borated water storage tank (BWST) and the capability to manually (locally or remotely) transfer suction to the reactor building sump such that water can be injected into the reactor vessel.

APPLICABLE SAFETY ANALYSES

The stable conditions associated with operation in MODE 3 with RCS temperature ≤ 350°F and in MODE 4, allow the operational requirements to be reduced.

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, the ECCS - Shutdown LCO satisfies Criterion 4 of 10 CFR 50.36.

LCO

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, two independent and redundant LPI trains are required to ensure sufficient LPI flow is available to the core. In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, an LPI train includes the pump, heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST and the capability to manually (locally or remotely) transfer suction to the reactor building sump.

During an event requiring LPI, a flow path is required to provide water from the BWST, via the LPI pumps and their respective supply headers, to the reactor vessel. In the long term, this flow path may be switched to take its supply from the reactor building sump.

LCO (continued)

A valve that is locked, sealed, or otherwise secured in its ES position is OPERABLE.

This LCO is modified by a Note that allows a Decay Heat Removal (DHR) train to be considered OPERABLE during alignment, when aligned, or when operating for decay heat removal, if it is capable of being manually (locally or remotely) realigned to the LPI mode of operation and is not otherwise inoperable. This provision is necessary because of the dual requirements of the components that comprise the low pressure injection/decay heat removal system.

APPLICABILITY

In MODES 1 and 2 and MODE 3 with RCS temperature > 350°F, the OPERABILITY requirements for the ECCS are covered by LCO 3.5.2.

In MODE 3 with RCS temperature ≤ 350°F and in MODE 4, two OPERABLE LPI trains are acceptable on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

In MODES 5 and 6, unit conditions are such that the probability of an event requiring LPI 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."

ACTIONS

A.1

If one LPI train is inoperable, the unit is not prepared to provide redundant, single failure proof LPI in response to events requiring ESAS. The 48 hour Completion Time to restore the LPI subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the unit in MODE 5, where an LPI train is not required.

B.1

When the Required Action and associated Completion Time of Condition A are not met, a controlled cooldown should be initiated. The allowed Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 from MODE 3 with RCS temperature ≤ 350°F in an orderly manner and without challenging unit systems.

ACTIONS (continued)

B.1 (continued)

This Required Action is modified by a Note that states that this Required Action is only required to be performed if one DHR train is OPERABLE. With both DHR pumps and heat exchangers inoperable, it would be unwise to require the unit to go to MODE 5, where the only available heat removal system is the LPI trains operating in the DHR mode. Therefore, the appropriate action is to initiate measures to restore one ECCS LPI train and to continue the actions until the train is restored to OPERABLE status.

C.1

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

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

C.2

Required Action C.2 requires that the unit be placed in MODE 5 within 24 hours. This Required Action is modified by a Note that states that this Required Action is only required to be performed if one DHR train is OPERABLE. This Required Action provides for those circumstances where the LPI trains may be inoperable but are otherwise capable of providing the necessary decay heat removal. Under this circumstance, the prudent action is to remove the unit from the Applicability of the LCO and place the unit in a stable condition in MODE 5. The Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases B 3.5.2 apply. This SR is modified by a Note that allows an LPI train to be considered OPERABLE during alignment and operation for DHR, if capable of being manually realigned (remote or local) to the LPI mode of operation and not otherwise inoperable. This allows operation in the DHR mode during MODE 4, if necessary.

REFERENCES

1. The applicable references from Bases B 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 Reactor Building Spray System by providing a source of borated water for ECCS and reactor building 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 Reactor Building Spray System. A motor operated isolation valve is provided in each header to allow the operator to isolate the BWST from the ECCS after the ECCS pump suction has been transferred to the reactor building 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 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 reactor building sump to support continued operation of the ECCS and reactor building spray pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains adequately shutdown following a LOCA.

Insufficient water inventory in the BWST could affect NPSH and result in insufficient cooling capability by the ECCS when the transfer to the recirculation mode occurs.

Improper boron concentrations could result in a reduction of adequate SDM or an excessive boric acid concentration in the core following a LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the reactor building.

APPLICABLE SAFETY ANALYSIS

During accident conditions, the BWST provides a source of borated water to the high pressure injection (HPI), low pressure injection (LPI), and reactor building spray pumps. As such, it provides reactor building cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown. The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of Bases B 3.5.2, "ECCS - Operating," and B 3.6.5, "Reactor Building Spray and Cooling Systems."

The limits on level of ≥ 38.4 feet and ≤ 42 feet are the accident analysis assumed values. These levels correspond to volumes of approximately 375,096 gallons and 405,090 gallons, respectively. These parameter values do not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures. Sufficient deliverable volume must be available to provide the operator adequate time to prepare for switchover to reactor building sump recirculation.

A second factor that affects the minimum required BWST level 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 reactor building spray pumps. This NPSH calculation is described in the SAR (Ref. 1), and the amount of water that enters the sump from the BWST and other sources is one of the input assumptions. The calculation does not take credit for more than the minimum assumed level 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 fourth factor is that the volume of water in the BWST must be limited to ensure that the resulting post-LOCA maximum reactor building water level is less than that used for environmental qualification of safety related components in the reactor building.

The level limits refer to the safety analysis assumed level. A certain amount of water is unusable because of tank discharge line location and other physical characteristics, and the time assumed for the operator to accomplish swapover to the sump.

The 2270 ppm limit for minimum boron concentration was established to ensure that, following a LOCA with a minimum BWST level, the reactor will remain adequately shutdown in the cold condition following mixing of the BWST and Reactor Coolant System (RCS) water volumes.

APPLICABLE SAFETY ANALYSES (continued)

The minimum and maximum concentration limits both ensure that the long term 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 2670 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. B&W has evaluated the flowpath inherent in the reactor vessel internals, commonly called the leakage gap flowpath, and demonstrated that the flowpath would be sufficient by itself to preclude boron precipitation (Ref. 2). As a secondary measure, 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.

The 40°F lower limit on the temperature of the solution in the BWST was established to ensure that the solution will not freeze. The 110°F upper limit on the temperature of the BWST contents is consistent with the maximum water temperature assumed in the safety analysis. These parameter values are considered to be nominal values. Additional allowances for instrument uncertainty are not required to be included in the implementing procedures.

In MODE 1, the BWST satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3). In MODES 2, 3 and 4, the BWST satisfies Criterion 4 of 10 CFR 50.36.

LCO

The BWST exists to ensure that an adequate supply of borated water is available to cool and depressurize the reactor building in the event of a DBA; to cool and cover the core in the event of a LOCA, thereby ensuring the reactor remains adequately shutdown following a DBA; and to ensure an adequate level exists in the reactor building sump to support ECCS and reactor building 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 Reactor Building Spray System OPERABILITY requirements. Since both the ECCS and Reactor Building 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, "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

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 Reactor Building Spray System may be able to perform its design functions. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the unit 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 Reactor Building Spray System can perform its design functions. Therefore, prompt action must be taken to restore the BWST to OPERABLE status or to place the unit 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.

C.1 and C.2

If the Required Actions and associated Completion Times are 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 unit 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 fluid will not freeze and that the fluid temperature will not be hotter than assumed in the safety analysis. These parameter values are considered to be nominal values and do not contain an allowance for instrument uncertainty. No additional allowances for instrument uncertainty are required to be included in the implementing procedures. The 24 hour Frequency is sufficient to identify a temperature change that would approach either temperature limit.

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 level is ≥ 38.4 feet and ≤ 42 feet ensures that a sufficient initial supply is available for injection and to support continued ECCS pump operation on recirculation. These levels correspond to volumes of approximately 375,096 gallons and 405,090 gallons, respectively. These parameter values do not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures. Since the BWST level is normally stable, 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 ≥ 2270 ppm and ≤ 2670 ppm ensures that the reactor will remain adequately shutdown following a LOCA. These parameter values do not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are included in the implementing procedures. Since the BWST level is normally stable, a 7 day sampling Frequency is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. SAR, Section 6.1.

2. Letter from A. C. Thadani (NRC) to P. S. Walsh (BWOG) dated March 9, 1993.

3. 10 CFR 50.36.

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.1 Reactor Building

BASES

BACKGROUND

The reactor building consists of the reactor building (RB) structure, its steel liner, and the penetrations of this liner and structure. The reactor building is designed to contain radioactive material that may be released from the reactor core following a design basis loss of coolant accident (LOCA). Additionally, the reactor building provides shielding from the fission product radioactivity that may be present in the reactor building atmosphere following an accident.

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

The reinforced concrete structure is required for structural integrity of the reactor building under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the reactor building. Maintaining the reactor building OPERABLE limits the leakage of fission product radioactivity from the reactor building 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 reactor building boundary are a part of the reactor building 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 reactor building isolation system except as provided in LCO 3.3.5, "Engineered Safeguards Actuation System (ESAS) Instrumentation," LCO 3.3.6, "ESAS Manual Initiation," and LCO 3.3.7, "ESAS Actuation Logic," 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, "Reactor Building Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Reactor Building Air Locks"; and

c. The equipment hatch is closed and sealed.

APPLICABLE SAFETY ANALYSES

The design basis for the reactor building is that the reactor building must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to reactor building OPERABILITY from high pressures and temperatures are a LOCA and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within the reactor building can occur from a LOCA. In the DBA analyses, it is assumed that the reactor building is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of reactor building leakage. The reactor building was designed with an allowable leakage rate of 0.2% of reactor building 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 La: the maximum allowable leakage rate at the calculated maximum peak reactor building pressure (Pa) resulting from the limiting design basis LOCA. The allowable leakage rate represented by La forms the basis for the acceptance criteria imposed on all reactor building leakage rate testing. La is assumed to be 0.2% per day in the safety analysis at Pa = 54.0 psig (Refs. 2 and 3).

In MODES 1 and 2, the reactor building satisfies Criterion 3 of 10 CFR 50.36 (Ref. 4). In MODES 3 and 4, the reactor building satisfies Criterion 4 of 10 CFR 50.36.

LCO

Reactor building OPERABILITY is maintained by limiting leakage to ≤ 1.0 La, except prior to the first startup after performing a required Reactor Building Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met. Reactor building OPERABILITY for leakage is attained by ensuring that the equipment hatch and both doors of the personnel and emergency air locks are closed and sealed, except as appropriate for maintenance activities, and that the other isolation devices are closed, deactivated in the closed position, or OPERABLE as required. Reactor building OPERABILITY is also maintained by monitoring the deviation of key design parameters of the RB structure from the original design configuration and ensuring that structural limits are not exceeded. Visual and other required examinations of tendons, anchorages and surfaces are performed periodically in accordance with station procedures. These procedures embody applicable requirements of the 1992 Edition with the 1992 Addenda of Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel Code, as set forth by 10CFR50.55a(g)(6)(ii)(B) (Ref. 5). Any degradations exceeding the Containment Inspection Program acceptance criteria during inspection surveillances will be reviewed under an engineering evaluation within 60 days of the completion of the inspection to determine what impact the degradation has on overall reactor building OPERABILITY, is if any. Compliance with this LCO, in conjunction with LCO 3.6.2, will ensure a reactor building configuration that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

LCO (continued)

Individual leakage rates specified for the reactor building air lock (LCO 3.6.2) 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 reactor building being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 La.

APPLICABILITY

In MODES 1, 2, 3 and 4, the reactor building OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in the lower MODES would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in the lower MODES. In MODES 5 and 6, the probability and consequences of events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the reactor building is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from the reactor building. The requirements for the reactor building during MODE 6 are addressed in LCO 3.9.3, "Reactor Building Penetrations."

ACTIONS

A.1

In the event the reactor building is inoperable, the reactor building 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 reactor building OPERABILITY during MODES 1, 2, 3, and 4. This time period also ensures the probability of an accident (requiring reactor building OPERABILITY) occurring during periods when reactor building is inoperable is minimal.

B.1 and B.2

If the Required Actions and associated Completion Times are 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the reactor building OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Reactor Building Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless its 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 Reactor Building Leakage Rate Testing Program leakage test is required to be ≤ 0.6 La for combined Type B and C leakage, and ≤ 0.75 La 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 La. At ≤ 1.0 La the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Reactor Building Leakage Rate Testing Program. These periodic testing requirements verify that the reactor building leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. SAR, Chapter 14.

3. SAR, Section 5.2.

4. 10 CFR 50.36.

5. 10CFR50.55a(g)(6)(ii)(B)

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.2 Reactor Building Air Locks

BASES

BACKGROUND

Reactor building air locks, also known as the personnel air lock and the emergency (or escape) air lock, form part of the reactor building pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder with a door at each end. The doors are interlocked to prevent simultaneous opening. 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 the reactor building. As such, closure of a single door supports the reactor building 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 the reactor building internal pressure results in increased sealing force on each door).

The reactor building air locks form part of the reactor building pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining the reactor building 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 the reactor building are a loss of coolant accident (LOCA) and a steam line break (Ref. 2). In the analysis of each of these accidents, it is assumed that the reactor building is OPERABLE such that release of fission products to the environment is controlled by the rate of the reactor building leakage. The reactor building was designed with an allowable leakage rate of $\leq$ 0.2% of the reactor building air weight per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as La: the maximum allowable reactor building leakage rate at the calculated maximum peak reactor building pressure, (Pa), 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.

In MODES 1 and 2, the reactor building air locks satisfy Criterion 3 of 10 CFR 50.36 (Ref. 4). In MODES 3 and 4, the reactor building air locks satisfy Criterion 4 of 10 CFR 50.36.

LCO

Each reactor building air lock forms part of the reactor building pressure boundary. As a part of the reactor building pressure boundary, the air lock safety function is related to control of the reactor building 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 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 (i.e., closed and sealed), 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 the reactor building does not exist when the reactor building is required to be OPERABLE. Closure and sealing of a single door in each air lock provides sufficient leakage barrier following postulated events. Nevertheless, both doors are normally closed and sealed when the air lock is not being used for normal entry into or exit from the reactor building.

APPLICABILITY

In MODES 1, 2, 3, and 4, the reactor building air lock OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in the lower MODES would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in the lower MODES. In MODES 5 and 6, the probability and consequences of events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the reactor building air locks are not required in MODE 5 to prevent leakage of radioactive material from the reactor building. The requirements for the reactor building air locks during MODE 6 are addressed in LCO 3.9.3, "Reactor Building Penetrations."

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 but capable of being swung, then it and the air lock barrel may be easily accessed for most repairs. It is preferred that an inoperable inner door be accessed from inside the reactor building 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 reactor building boundary is not intact (during access through the OPERABLE door). Opening the OPERABLE door, even if it means the reactor building boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the reactor building 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 conditions permit, entry and exit should be via an OPERABLE air lock.

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 reactor building leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Reactor Building."

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

With one air lock door inoperable in one or more reactor building air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected reactor building air lock.

This ensures that a leak tight reactor building 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 the reactor building 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 reactor building leakage boundary is maintained. The Completion Time of once per 31 days 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.

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;

ACTIONS (continued)

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

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. Reactor building entry may be required to perform Technical Specification (TS) Surveillances and Required Actions, as well as other activities on equipment inside the reactor building 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 reactor building 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 reactor building 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.

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 reactor building 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

ACTIONS (continued)

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

per door has failed), the reactor building 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 unit shutdown. In addition, even with both doors failing the seal test, the overall reactor building leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected reactor building 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 the reactor building 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 Required Actions and associated Completion Times are 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining the reactor building air locks OPERABLE requires compliance with the leakage rate test requirements of the Reactor Building 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 reactor building OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall reactor building leakage rate. The Frequency is required by the Reactor Building 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 reactor building leakage rate.

SURVEILLANCE REQUIREMENTS (continued)

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 reactor building pressure, closure of either door will support the reactor building OPERABILITY. Thus, the door interlock feature supports the reactor building OPERABILITY while the air lock is being used for personnel transit in and out of the reactor building. 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 reactor building 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 18 months. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage, and the potential for loss of reactor building OPERABILITY if the Surveillance were performed with the reactor at power. The 18 month Frequency for the interlock is justified based on generic operating experience. The 18 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not expected to be challenged during use of the airlock.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. SAR, Chapter 14.

3. SAR, Chapter 5.

4. 10 CFR 50.36.

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.3 Reactor Building Isolation Valves

BASES

BACKGROUND

The reactor building isolation valves form part of the reactor building pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on an automatic isolation signal. These isolation devices consist of either passive devices or active (automatic) devices. 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 reactor building isolation valves) make up the Reactor Building Isolation System.

Reactor building isolation occurs upon receipt of a high reactor building pressure signal. The reactor building isolation signal closes automatic reactor building isolation valves in fluid penetrations not required for operation of engineered safeguard systems to prevent leakage of radioactive material. Also, upon receipt of a low RCS pressure signal, certain automatic reactor building isolation valves isolate. Other penetrations are isolated by the use of valves in the closed position or blind flanges. As a result, the reactor building isolation valves (and blind flanges) help ensure that the reactor building atmosphere will be isolated in the event of a release of radioactive material to the reactor building atmosphere from the RCS following a Design Basis Accident (DBA).

OPERABILITY of the reactor building isolation valves (and blind flanges) supports the reactor building OPERABILITY during accident conditions.

The OPERABILITY requirements for the reactor building isolation valves help ensure that the reactor building is isolated. Therefore, the OPERABILITY requirements provide assurance that the reactor building function assumed in the safety analysis will be maintained.

The Reactor Building Purge System is part of the Reactor Building Ventilation System. The Reactor Building Purge System was designed for intermittent operation, providing a means of removing airborne radioactivity caused by minor leakage from the RCS prior to personnel entry into the reactor building. The Reactor Building Purge System consists of one 24 inch line for exhaust and one 24 inch line for supply, with supply and exhaust fans. The reactor building purge supply and exhaust lines each contain two isolation valves that receive a reactor building isolation signal.

BACKGROUND (continued)

Failure of the purge valves to close following a design basis event would cause a significant increase in the radioactive release because of the large reactor building leakage path introduced by these 24 inch purge lines. Failure of the purge valves to close would result in leakage considerably in excess of the reactor building design leakage rate of ≤ 0.2% of reactor building air weight per day (La) (Ref. 1). The 24 inch purge valves are not tested for automatic closure from their open position under DBA conditions. Therefore, the 24 inch supply and exhaust purge valves are maintained closed with the handswitch keys removed (SR 3.6.3.1) in MODES 1, 2, 3, and 4 to ensure the reactor building boundary is maintained.

APPLICABLE SAFETY ANALYSES

The reactor building isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the reactor building boundary during major accidents. As part of the reactor building boundary, the reactor building isolation valve OPERABILITY supports leak tightness of the reactor building. Therefore, the safety analysis of any event requiring isolation of the reactor building is applicable to this LCO.

The DBAs that result in a release of radioactive material within the reactor building are a loss of coolant accident (LOCA) and a main steam line break (Ref. 2). In the analysis for each of these accidents, it is assumed that the reactor building isolation valves are either closed or function to close. This ensures that potential paths to the environment through the reactor building isolation valves (including reactor building purge valves) are minimized. The safety analysis assumes that the 24 inch purge valves are closed at event initiation.

The LOCA analysis assumes a fixed amount of core inventory escapes. No mechanistic scenario is evaluated to determine what portion of the inventory is released prior to closure of the reactor building isolation valves. Industry standards for sizing valve operators govern the closure times of the reactor building isolation valves.

ANO-1 does not currently allow reactor building purging in MODES 1, 2, 3, and 4. Therefore, each of the reactor building purge valves is required to remain closed with its handswitch key removed during MODES 1, 2, 3, and 4. This prevents inadvertent actuation of the reactor building purge valves while in MODES 1, 2, 3, and 4. The purge system valve design prevents a single failure from compromising the reactor building boundary as long as the system is operated in accordance with the subject LCO.

In MODES 1 and 2, the reactor building isolation valves satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3). In MODES 3 and 4, the reactor building isolation valves satisfy Criterion 4 of 10 CFR 50.36.

LCO

Reactor Building isolation valves form a part of the reactor building boundary. The reactor building isolation valve safety function is related to minimizing the loss of reactor coolant inventory and establishing the reactor building boundary during a DBA.

The automatic power operated reactor building isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 24 inch purge valves must be maintained closed. The valves covered by this LCO are listed in the SAR (Ref. 4). Their associated stroke times are contained in the Inservice Testing Program. The normally closed manual reactor building isolation valves are considered OPERABLE when the valves are closed, blind flanges are in place, or open under administrative controls. These passive isolation valves/devices are listed in Reference 4.

The reactor building isolation valve leakage rates are addressed by LCO 3.6.1, "Reactor Building," as Type C testing.

This LCO provides assurance that the reactor building isolation valves will perform their designated safety functions to minimize the loss of reactor coolant inventory and establish the reactor building boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3 and 4, the reactor building isolation valves OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in the lower MODES would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in the lower MODES. In MODES 5 and 6, the probability and consequences of events are reduced due to the pressure and temperature limitations of these MODES. The requirements for reactor building isolation valves during MODE 5 and 6, primarily related to movement of irradiated fuel in the reactor building, are addressed in LCO 3.9.3, "Reactor Building Penetrations."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated individual 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 reactor building isolation is indicated. Due to ALARA concerns, it is permissible for this dedicated individual to be stationed in a nearby lower dose area provided the intent of rapidly isolating the penetration is retained. Due to the size of the reactor building purge line penetration and the fact that those penetrations exhaust directly from the reactor building atmosphere to the environment, the penetration flow paths containing these valves may not be opened under administrative controls.

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 reactor building isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable reactor building 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 reactor building isolation valve.

In the event isolation valve leakage results in exceeding the overall reactor building 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 reactor building isolation valve in one or more penetration flow paths is inoperable, 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 reactor building 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 the reactor building. Required Action A.1 must be completed within the 48 hour Completion Time. The specified time period is reasonable, considering the time required to isolate the penetration and the relative importance of supporting reactor building OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 48 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 the reactor building 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, through a system walkdown, that those isolation devices outside the reactor building and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside the reactor building" 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 the reactor building, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" 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.

ACTIONS (continued)

A.1 and A.2 (continued)

Condition A has been modified by a Note indicating this Condition is only applicable to those penetration flow paths with two reactor building isolation valves. For penetration flow paths in closed systems with only one reactor building 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 reactor building isolation valves in one or more penetration flow paths inoperable, 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 verification is necessary to assure leak tightness of the reactor building 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 reactor building isolation valves. Condition A of this LCO addresses the condition of one reactor building isolation valve inoperable in this type of penetration flow path.

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one reactor building 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 structural integrity of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting reactor building 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 that reactor building 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.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one reactor building isolation valve and a closed system. The service water system is the only closed system within the reactor building to which Specification 3.6.3 Condition C applies. The service water system within the reactor building is designed to seismic category 1 standards. Because the system is located outside of the secondary shield walls, it is protected from missiles and pipe whip from reactor coolant system components. The service water system is capable of withstanding reactor building design pressure and temperature and is designed to withstand the LOCA accident transient and environment. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

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.

ACTIONS (continued)

D.1 and D.2

If the Required Actions and associated Completion Times are 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 24 inch reactor building purge isolation valve in the purge system supply and exhaust is required to be verified closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of the reactor building is not caused by an inadvertent opening of a reactor building purge 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 during MODES 1, 2, 3, and 4. A reactor building purge valve that is closed must have motive power to the valve operator removed. This can be accomplished by removing the valve handswitch key. The Frequency is consistent with other reactor building isolation valves discussed in SR 3.6.3.2.

SR 3.6.3.2

This SR requires verification that each reactor building isolation manual valve and blind flange located outside the reactor building 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 reactor building boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those reactor building isolation valves outside the reactor building and capable of being mispositioned are in the correct position. Since verification of valve position for the reactor building isolation valves outside the reactor building is relatively easy, the 31 day Frequency was chosen to provide added assurance of the correct positions. The SR specifies that the reactor building 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2 (continued)

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 reactor building 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 reactor building isolation manual valve and blind flange that is located inside the reactor building 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 reactor building boundary is within design limits. For reactor building isolation valves inside reactor building, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate, since these reactor building isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that reactor building 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 reactor building 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 reactor building isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period consistent with the industry standards for sizing valve operators. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

Automatic reactor building isolation valves close on a reactor building isolation signal to prevent leakage of radioactive material from the reactor building following a DBA. This SR ensures that each automatic reactor building isolation valve will actuate to its isolation position on a reactor building isolation signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. SAR, Chapter 5.

2. SAR, Chapter 14.

3. 10 CFR 50.36.

4. SAR, Table 5-1.

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.4 Reactor Building Pressure

BASES

BACKGROUND

The reactor building pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). Additionally, keeping the reactor building pressure within the limits maintains the initial conditions assumed for the reactor building design basis accident (DBA) and Emergency Core Cooling System (ECCS) analyses.

The reactor building pressure is a process variable that is monitored and controlled. The reactor building pressure limits are derived from the input conditions used in the reactor building DBA and ECCS analyses. Should operation occur outside these limits coincident with a DBA, post accident reactor building pressures and ECCS performance could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Reactor building internal pressure is an initial condition used in the DBA analyses to establish the maximum peak reactor building internal pressure. The limiting DBAs considered, relative to reactor building pressure, are the LOCA and SLB. The worst-case LOCA generates larger mass and energy release than the worst-case SLB. Thus, the LOCA event bounds the SLB event from the reactor building peak pressure standpoint (Ref. 1).

The initial pressure condition used in the reactor building analysis was 14.7 psia. The LCO limit of 3.0 psig ensures that, in the event of an accident, the design pressure of 59 psig for the reactor building is not exceeded. The LCO limit of -1.0 psig ensures that operation within the design assumptions for ECCS is maintained (Ref. 2). The LCO limit of 3.0 psig does not consider instrument uncertainty. The LCO limit of -1.0 psig is considered to be an as-indicated value.

For certain aspects of transient accident analyses, maximizing the calculated reactor building 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 the reactor building backpressure. Therefore, for the reflood phase, the reactor building backpressure is assumed in a manner designed to conservatively minimize, rather than maximize, the reactor building pressure response in accordance with 10 CFR 50, Appendix K (Ref. 3).

BACKGROUND (continued)

In MODES 1 and 2, the reactor building pressure satisfies Criterion 2 of 10 CFR 50.36 (Ref. 4). In MODES 3 and 4, the reactor building pressure satisfies Criterion 4 of 10 CFR 50.36.

LCO

Maintaining the reactor building pressure less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak reactor building accident pressure will remain below the reactor building design pressure.

Additionally, keeping the reactor building pressure within the limits maintains the initial conditions assumed for the ECCS analyses.

APPLICABILITY

In MODES 1, 2, 3 and 4, the reactor building OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in the lower MODES would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in the lower MODES. Since maintaining reactor building pressure within design basis limits is essential to ensure that the peak reactor building pressure from an accident does not exceed the reactor building design pressure, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining the reactor building pressure within the limits of the LCO is not required in MODES 5 and 6.

ACTIONS

A.1

When the reactor building pressure is not within the limits of the LCO, the reactor building 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 reactor building analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Reactor Building," which requires that the reactor building be restored to OPERABLE status within 1 hour.

ACTIONS (continued)

B.1 and B.2

If the Required Actions and associated Completion Times are 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that the reactor building pressure is within limits ensures that operation remains within the limits assumed in the ECCS and the reactor building analyses. The 12 hour Frequency of this SR was developed after taking into consideration operating experience related to trending of the reactor building pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to an abnormal reactor building pressure condition.

REFERENCES

1. SAR, Chapter 14.

2. SAR, Chapter 5.

3. 10 CFR 50, Appendix K.

4. 10 CFR 50.36.

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.5 Reactor Building Spray and Cooling Systems

BASES

BACKGROUND

The Reactor Building Spray and Reactor Building Cooling systems provide reactor building atmosphere cooling to limit post accident pressure and temperature in the reactor building to less than the design values. In the event of a Design Basis Accident (DBA), reduction of reactor building pressure reduces the release of fission products from the reactor building to the environment. The Reactor Building Spray and Reactor Building Cooling systems are designed to meet the requirements as discussed in the Safety Analysis Report (SAR), specifically, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal System," GDC 40, "Testing of Containment Heat Removal System," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems" (Ref. 1).

The Reactor Building Cooling System and Reactor Building Spray System are Engineered Safeguards (ES) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Reactor Building Spray System and Reactor Building Cooling System provide redundant reactor building heat removal operation. The Reactor Building Spray System and Reactor Building Cooling System provide redundant methods to limit and maintain post accident conditions to less than the reactor building design values.

Reactor Building Spray System

The Reactor Building Spray System consists of two separate trains of equal capacity, each capable of meeting the design basis. Each train includes a reactor building spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ES bus. The borated water storage tank (BWST) supplies borated water to the Reactor Building Spray System during the injection phase of operation. In the recirculation mode of operation, Reactor Building Spray System pump suction is manually transferred to the reactor building sump.

The Reactor Building Spray System provides a spray of borated water into the upper regions of the reactor building to reduce the reactor building pressure and temperature during a DBA. During MODE 1 or 2, the Reactor Building Spray System supports the Spray Additive System function of iodine removal by providing the distribution mechanism. In MODES 3 and 4, sodium hydroxide is not mixed with the spray flow. In the recirculation mode of operation, heat is removed from the reactor building sump water by the decay heat removal coolers. The Reactor Building Spray System provides adequate spray coverage to meet the system design requirements for reactor building heat removal.

BACKGROUND (continued)

The Reactor Building Spray System is actuated automatically by a reactor building High-High pressure signal. An automatic actuation opens the Reactor Building Spray System pump discharge valves and starts the Reactor Building Spray System pumps.

Reactor Building Cooling System

The Reactor Building Cooling System during normal operations consists of five (5) chilled water supplied cooling coils each in-line with a fan. Four (4) of these fan and chiller coil circuits have in-line service water cooling coils. During normal operations the service water to these coils is isolated. The post accident configuration of the Reactor Building Cooling System consists of the four service water cooling coils and their respective axial flow fans and dampers arranged as two independent trains.

Upon receipt of an Engineered Safeguards Actuation System (ESAS) RB high pressure signal, the four (4) fans associated with the service water coils receive a start signal, the chilled water is isolated, the service water supply and discharge valves open, the RB cooler bypass dampers open (which causes the return air to bypass the chilled water coils) and the RB cooler backdraft dampers receive an open signal. This equipment is powered from class 1E electrical power.

Each of the four (4) service water coil and fan air paths receives return air separately and directly from the RB atmosphere and discharges through ducting to a common plenum for distribution to the various reactor building spaces. The four (4) fans are mounted vertically on the ventilation units and are axial-flow type. The fan motors are single speed and operate in post-accident conditions at the same speed as normal conditions. Reducing fan motor speed during accident conditions is not required due to the reduced suction pressure drop (and hence fan load relative to normal conditions) created by bypassing the chilled water coils. An RB cooling train consists of two coolers and their associated fans which have sufficient capacity to meet post accident heat removal requirements. Conservatively each reactor building emergency cooling train consists of two fans powered from the same emergency bus and their associated coils, but other combinations may be justified by an engineering evaluation (Ref. 2). The continuous availability of appropriate service water flow to the RB Cooling System is assured by the periodic addition of a biocide to the Service Water System.

APPLICABLE SAFETY ANALYSES

The Reactor Building Spray System and the Reactor Building Cooling System reduce the temperature and pressure following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break. The postulated DBAs are analyzed, with regard to the reactor building ES systems, assuming the loss of one ES bus. This is the worst-case single active failure, resulting in one train of the Reactor Building Spray System and one train of the Reactor Building Cooling System being inoperable.

APPLICABLE SAFETY ANALYSES (continued)

The analysis and evaluation show that, under the worst-case scenario, the highest peak reactor building pressure is 53.96 psig (experienced during a LOCA). The analysis shows that the peak reactor building temperature is 283.9°F (experienced during a LOCA). Both results are conservatively reported as 54 psig and 284°F, respectively, and are less than the design values. The analyses and evaluations assume a power level of 2568 MWt, one reactor building spray train and one reactor building cooling train operating, and initial (pre-accident) conditions of 140°F and 14.7 psia. The analyses also assume a delayed initiation to provide conservative peak calculated reactor building pressure and temperature responses.

The assumed Reactor Building Spray System total delay time of 300 seconds conservatively envelopes diesel generator (DG) startup (for loss of offsite power), block loading of equipment, the reactor building spray pump startup, and spray line filling (Ref. 3).

The reactor building cooling train performance for post accident conditions is given in Reference 2. The result of the analysis is that each train can provide 100% of the required cooling capacity during the post accident condition. The train post accident cooling capacity under varying reactor building ambient conditions, is also shown in Reference 2.

The assumed Reactor Building Cooling System total delay time of 300 seconds conservatively envelopes signal delay, DG startup, block loading of equipment, fan startup, and service water pump startup times (Ref. 3).

In MODES 1 and 2, the Reactor Building Spray System and the Reactor Building Cooling System satisfy Criterion 3 of 10 CFR 50.36 (Ref. 4). In MODES 3 and 4, the Reactor Building Spray System and the Reactor Building Cooling System satisfy Criterion 4 of 10 CFR 50.36.

LCO

During a DBA, the combination of one reactor building cooling train and one reactor building spray train is sufficient to reduce the reactor building pressure and temperature. One reactor building spray train is required, during MODE 1 or 2, to support the Spray Additive System in the removal of iodine from the reactor building atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, in MODES 1 and 2, two reactor building spray trains and two reactor building 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. In MODE 3 or 4, one reactor building spray train and one reactor building cooling train are required to be operable. The LCO is provided with a Note which clarifies this requirement.

LCO (continued)

The Reactor Building Spray System includes spray pumps, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon an Engineered Safeguards Actuation System signal and manually transferring suction to the reactor building sump.

The Reactor Building Cooling System includes cooling coils, dampers, axial flow fans, single speed fan motors, instruments, and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1, 2, 3, and 4, the reactor building OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in the lower MODES would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in the lower MODES. Since an event could cause a release of radioactive material in the reactor building as well as a temperature and pressure rise, the Reactor Building Spray System and the Reactor Building Cooling System are required to be OPERABLE 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. Thus, the Reactor Building Spray System and the Reactor Building Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one reactor building spray train inoperable in MODE 1 or 2, the inoperable reactor building spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to support the iodine removal and perform the reactor building cooling functions. The 72 hour Completion Time takes into account the redundant heat and iodine removal capability afforded by the OPERABLE reactor building cooling and spray trains, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based on the low probability of coincident entry into two Conditions in this LCO coupled with the low probability of an accident occurring during this time. Refer to Section 1.3, Completion Times for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time

ACTIONS (continued)

B.1

With one of the reactor building cooling trains inoperable in MODE 1 or 2, the inoperable reactor building cooling train must be restored to OPERABLE status within 7 days. The remaining OPERABLE components are capable of providing at least 100% of the heat removal needs after an accident. The 7 day Completion Time takes into account the redundant heat removal capabilities afforded by combinations of the Reactor Building Spray System and Reactor Building Cooling System and the low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action B.1 is based on the low probability of coincident entry into two Conditions in this LCO coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the "from discovery of failure to meet the LCO" portion of the Completion Time.

C.1

With two of the reactor building cooling trains inoperable in MODE 1 or 2, one of the reactor building cooling trains must be restored to OPERABLE status within 72 hours. The remaining spray system components (both spray trains are OPERABLE or else Condition G is entered) support iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time takes into account the redundant heat removal capabilities afforded by the Reactor Building Spray System and the low probability of a DBA occurring during this period.

D.1

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

E.1

With either one required reactor building (RB) spray train or one required reactor building cooling train inoperable in MODE 3 or 4, the inoperable train must be restored to OPERABLE status in 36 hours. The 36 hour Completion Time is reasonable based on consideration of the cooling capacity of the remaining required train of RB cooling or RB spray, the reduced reactor coolant energy in these MODES, and the short time spent in these MODES.

ACTIONS (continued)

F.1

If the Required Action and associated Completion Time of Condition E are 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 MODE 5 within 36 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions in an orderly manner and without challenging unit systems.

G.1

With two reactor building spray trains inoperable in MODE 1 or 2, or any combination of three or more reactor building spray and reactor building cooling trains inoperable in MODE 1 or 2, or one required reactor building spray train and one required reactor building cooling train inoperable in MODE 3 or 4, then LCO 3.0.3 must be entered immediately. The first part of this Condition addresses the loss of Spray Additive System support which would result from two inoperable reactor building spray trains in MODE 1 or 2. The second part of this Condition considers the loss of adequate reactor building cooling capacity in MODE 1 or 2 which would result from the loss of three or more of the four RB spray and RB cooling trains. Finally, the third part of this Condition addresses loss of reactor building cooling capability in MODES 3 and 4 when only one train of RB spray and one train of RB cooling are required.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the reactor building spray flow path provides assurance that the proper flow paths will exist for the Reactor Building 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 or control room indication, that those valves outside the reactor building and capable of potentially being mispositioned are in the correct position.

SR 3.6.5.2

Operating each required reactor building cooling train fan unit for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. This SR is performed by starting (unless operating) each operational cooling fan from the control room. The 31 day Frequency was

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.2 (continued)

developed considering the known reliability of the fan units and controls, the redundancy available, and the low probability of a significant degradation of the reactor building cooling trains occurring between surveillances and has been shown to be acceptable through operating experience.

SR 3.6.5.3

Verifying that a service water flow rate of 1200 gpm is provided to each required reactor building cooling train provides assurance that the original design flow rate is being achieved and that the service water flow rate is not degrading (Ref. 3). Assurance that the flow doesn't degrade by biological fouling between surveillances is provided by the addition of a biocide to the Service Water System whenever the service water temperature is between 60°F and 80°F. The Frequency was developed considering the known reliability of the system, the redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.5.4

Verifying that each required reactor building 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. Acceptable performance will be indicated if the pump starts, operates for fifteen minutes, and the discharge pressure and flow rate are within ± 10 % of a point on the pump head curve. Flow and differential pressure are measured during normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 5). Since the Reactor Building Spray System pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms the discharge pressure and flow rate are within ± 10 % of a point on the pump head curve and is indicative of overall pump performance. Such inservice tests confirm component OPERABILITY, trend performance, and may detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.5.5 and SR 3.6.5.6

These SRs require verification that each automatic reactor building spray valve actuates to its correct position and that each reactor building spray pump starts upon receipt of an actual or simulated actuation signal. The SRs are considered satisfactory if visual observation and control board indication verifies that all components have responded to the actuation signal properly. This SR is not required for valves that are locked, sealed, or otherwise secured in position under

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.5 and SR 3.6.5.6 (continued)

administrative controls. During testing of the spray pump, the reactor building isolation valve in the spray line is closed with its breaker open to prevent spraying the reactor building. After spray pump performance is verified, the pump is stopped. Its breaker is racked down to prevent restart. Power is then restored to the reactor building isolation valve for valve testing. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.5.7

This SR requires verification by control board indication that each required reactor building cooling train actuates upon receipt of an actual or simulated actuation signal. The 18 month Frequency has been shown to be acceptable through operating experience. See SR 3.6.5.5 and SR 3.6.5.6, above, for further discussion of the basis for the 18 month Frequency.

SR 3.6.5.8

With the reactor building spray header isolated and drained of any solution, low pressure air or smoke can be blown through test connections. Performance of this Surveillance demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the reactor building during an accident is not degraded. Due to the passive nature of the design of the nozzles, a test at 10 year intervals is considered adequate to detect obstruction of the spray nozzles.

REFERENCES

1. SAR, Section 1.4.
2. SAR, Chapter 6.
3. SAR, Chapter 14.
4. 10 CFR 50.36.
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 REACTOR BUILDING SYSTEMS

B 3.6.6 Spray Additive System

BASES

BACKGROUND

The Spray Additive System reduces the iodine fission product inventory in the reactor building atmosphere resulting from a Design Basis Accident (DBA). The Reactor Building Spray System supports the Spray Additive System iodine removal function by providing a distribution mechanism for the solution.

The Reactor Building Spray System and Spray Additive System perform no function during normal operations. In the event of a loss of coolant accident (LOCA), the Spray Additive System will be automatically actuated upon a reactor building high-high pressure signal by the Engineered Safeguards Actuation System. Actuation of the Spray Additive System opens the sodium hydroxide isolation valves, which are powered from independent buses. When the valves are open, the sodium hydroxide solution is ready to be introduced into the RB Spray System headers.

Radioiodine in its various forms is the fission product of primary concern in the evaluation of the dose consequences of an accident. It is absorbed by a sprayed solution from the reactor building atmosphere. The spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Sodium hydroxide (NaOH), because of its stability when exposed to radiation and elevated temperature, is the spray additive utilized.

The NaOH tank is designed and located to permit gravity draining into the Reactor Building Spray System. The sodium hydroxide volume requirement is given in gallons for compatability with the design analyses. The minimum NaOH tank volume of 9000 gallons preserves the required NaOH solution contribution from the tank to the post-LOCA minimum sump level. Both the Reactor Building Spray System pumps initially take suction from the borated water storage tank (BWST) via two independent flow paths. The NaOH tank has a common outlet that splits and feeds each of the Reactor Building Spray System suction lines. The system is designed to discharge at a rate commensurate with the draining rate of the BWST so that all borated water injected is mixed with sodium hydroxide.

The flow rate is proportioned to provide a spray solution with a pH which is alkaline (Ref. 1). The range of 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 range also considers the environmental qualification of equipment in the reactor building that may be subjected to the spray.

APPLICABLE SAFETY ANALYSES

The reactor building Spray Additive System provides for the effective removal of airborne iodine within the reactor building following a DBA.

Following the assumed release of radioactive materials into the reactor building, the reactor building is assumed to leak at its design value following the accident. The analysis assumes that most of the reactor building volume is covered by the spray.

The delay time assumed for the Spray Additive System is the same as for the Reactor Building Spray System and is discussed in the Bases for LCO 3.6.5, "Reactor Building Spray and Cooling Systems."

The LOCA analyses assume that one train of the Reactor Building Spray System/Spray Additive System is inoperable and that sufficient NaOH volume is added to the remaining Reactor Building Spray System flow path.

In the evaluation of the worst-case LOCA, the safety analysis assumed that an alkaline reactor building spray effectively reduced the airborne iodine.

Each Reactor Building Spray System suction line is equipped with its own gravity feed from the NaOH tank. Therefore, in the event of a single failure within the Spray Additive System (i.e., NaOH isolation valve failure), NaOH will still be mixed with the borated water, establishing the alkalinity to provide effective iodine removal.

The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36 (Ref. 2).

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the NaOH solution must be sufficient to provide NaOH into the spray flow until the Reactor Building Spray System suction path is switched from the BWST to the reactor building sump and to raise the long term sump solution pH to a level conducive to iodine removal. The long term sump solution pH is in the alkaline range. This pH maximizes the effectiveness of the iodine retention mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.

APPLICABILITY

In MODES 1 and 2, the reactor building OPERABILITY for the limiting Design Basis Accidents is based on full power operation. Although reduced power in a lower MODE would not require the same level of accident mitigation performance, there are no accident analyses for reduced performance in a lower MODE. Although the core is designed to retain structural integrity during an accident, fuel failure with resultant radioactive material release is postulated and the Spray Additive System is required OPERABLE in MODES 1 and 2.

In MODES 3 and 4, there is no postulated fuel failure contribution to radioactive material release and significantly less need for iodine removal capacity. Also, because of the limited time spent in these MODES, the probability of an event requiring use of the Spray Additive System is low. Therefore, the Spray Additive System is not required to be OPERABLE in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With the Reactor Building Spray Additive System inoperable, the system must be restored to OPERABLE status within 72 hours. The pH adjustment capability of the spray solution for corrosion protection and iodine removal enhancement is reduced or non-existent in this Condition. The Reactor Building Spray System would still be available and would remove some iodine from the reactor building atmosphere in the event of a LOCA. The 72 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst-case DBA occurring during this period.

B.1

If the Required Actions and associated Completion Times are 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 MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment of NaOH manual, power operated, and automatic valves in the Spray Additive System flow path provides assurance that the system is able to provide NaOH to the Reactor Building Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown or control room indication, that those valves outside the reactor building capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

To provide the most effective iodine removal, the reactor building spray should be an alkaline solution. Since the BWST contents are normally acidic, the NaOH tank must provide a sufficient volume of NaOH to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The NaOH tank solution minimum volume of 9000 gallons corresponds to a tank level of approximately 26 feet at a temperature of 77°F and a NaOH concentration of 5.0 wt%. This parameter does not contain an allowance for instrument uncertainty. Additional allowances for instrument uncertainty are contained in the implementing procedures. The minimum NaOH tank volume preserves the required NaOH solution contribution from the tank to the post-LOCA minimum sump level. The 184 day Frequency is based on the low probability of an undetected change in tank volume occurring during the SR interval (the tank is isolated during normal unit operations). Tank level is also indicated and alarmed in the control room, such that there is a high confidence that a substantial change in level would be detected.

SR 3.6.6.3

This SR provides verification of the NaOH concentration in the NaOH tank and is sufficient to ensure that the spray solution being injected into the reactor building is at the correct pH level. The concentration of NaOH in the NaOH tank must be determined by chemical analysis. There is no instrument uncertainty included in the surveillance limit values. Additional allowances for instrument uncertainty are contained in the implementing procedures. The 184 day Frequency is sufficient to ensure that the concentration of NaOH in the tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on 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 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. SAR, Chapter 6.

2. 10 CFR 50.36.

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.

Eight MSSVs are located on each main steam header, outside the reactor building, upstream of the main steam isolation valves, as described in the SAR, Section 10.3 (Ref. 1). The MSSV capacity is adequate to meet the requirements of the ASME Code, Section III (Ref. 2). The total capacity of 14 MSSVs is greater than the total steam flow at 102% RTP. The MSSV design includes staggered setpoints (Ref. 1) so that only the needed number of valves will actuate. Staggered setpoints reduce the potential for valve chattering because of insufficient steam pressure to fully open the valves.

APPLICABLE SAFETY ANALYSES

The design basis of the MSSVs (Ref. 2) is to limit secondary system pressure to ≤ 110% of design pressure when passing 102% of design steam flow (100% plus 2% heat balance error). The MSSVs ensure that the design basis requirements are met for any abnormality or accident considered in the SAR.

The events that may assume use of the MSSVs are those characterized as decreased heat removal events. MSSV use may be assumed during mitigation of the following events:

a. Loss of Load (SAR, Chapter 14 (Ref. 3));

b. Steam generator tube rupture; and

c. Small break loss of coolant (Ref. 3).

The full power turbine trip coincident with a loss of condensate heat sink establishes the required MSSV relief capacity (Ref. 4).

In MODES 1 and 2, the MSSVs satisfy Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODE 3, the MSSVs satisfy Criterion 4 of 10 CFR 50.36.

LCO

The MSSVs are provided to prevent overpressurization as discussed in the Applicable Safety Analysis section of these Bases. The LCO requires fourteen MSSVs (seven on each main steam line) to be OPERABLE to ensure compliance with the ASME Code following DBAs initiated at full power. Operation with less than the required complement of MSSVs requires a limitation on unit THERMAL POWER and adjustment of the Reactor Protection System (RPS) nuclear overpower trip setpoint. The minimum number of OPERABLE MSSVs per steam generator for various power levels and the associated maximum allowable nuclear overpower trip setpoint are identified in Table 3.7.1-1. 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 SR 3.7.1.1.

The safety function of the MSSVs is to open, relieve steam generator overpressure, and reseat when pressure has been reduced.

OPERABILITY of the MSSVs requires periodic surveillance testing in accordance with the Inservice Testing Program.

With all MSSVs OPERABLE, at least one MSSV per steam generator is set at 1050 psig nominal, while the remaining MSSVs per steam generator are set at varied pressures up to and including 1100 psig nominal. The lift settings 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.

The LCO is modified by a Note that allows all but one MSSV on each main steam header to be gagged and the setpoints for the two (one on each header) OPERABLE MSSVs to be reset for the duration of hydrotesting in MODE 3. This is necessary to allow the hydrotest pressure to be attained.

APPLICABILITY

In MODES 1, 2, and 3, the MSSVs are required to be OPERABLE to prevent overpressurization of the main steam system.

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, provided the ALLOWABLE THERMAL POWER and RPS nuclear overpower trip setpoint are reduced as required by Table 3.7.1-1. These values are based on the following formulas:

$$RP = \frac{Y}{Z} \times 100\%$$

and

$$SP = \frac{Y}{Z} \times W$$

where:

W = Nuclear overpower trip setpoint for four pump operation as specified in LCO 3.3.1, "Reactor Protection System (RPS)";

Y = Total OPERABLE MSSV relieving capacity per steam generator based on a summation of individual OPERABLE MSSV relief capacities per steam generator (the available capacity of each MSSV is 801,428 lbm/hour);

Z = Required relieving capacity per steam generator of 5,610,000 lbm/hour;

RP = Reduced power requirement (not to exceed RTP); and

SP = Nuclear overpower trip setpoint (not to exceed W).

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 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, on operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

ACTIONS (continued)

B.1 and B.2

With one or more steam generators with less than two MSSVs OPERABLE, or if the Required Actions and associated Completion Times are not 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 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 MSSV lift setpoints in accordance with the Inservice Testing Program. The safety and relief valve tests are performed in accordance with ANSI/ASME OM-1-1987 (Ref. 6) and include the following 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 ANSI/ASME Standard requires the testing of all valves every 5 years, with a minimum of 20% of the valves tested every 24 months. Reference 6 provides the activities and frequencies necessary to satisfy the requirements and allows an as-found ± 3% setpoint tolerance. Although not required by the IST Program, 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.

REFERENCES

1. SAR, Section 10.3.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.

3. SAR, Chapter 14.

4. AREVA/FANP Document 77-5018959-01, “ANO-1 Overpressure Protection Report.”

5. 10 CFR 50.36.

6. ANSI/ASME OM-1-1987.

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 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, the reactor building. The MSIVs are downstream from the main steam safety valves (MSSVs) and emergency feedwater pump turbine's steam supply to prevent their being isolated from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the other, and isolates the turbine, Turbine Bypass System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam line isolation (MSLI) signal as described in LCO 3.3.11, “Emergency Feedwater Initiation and Control (EFIC) System Instrumentation.” The EFIC System is designed to prevent the simultaneous blowdown of both steam generators. The MSIVs may also be actuated manually.

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the analysis for the steam line break as discussed in the SAR, Section 14.2 (Ref. 1). The analysis assumes a break in the main steam line upstream of an MSIV. Closure of the MSIVs isolates blowdown from the unaffected steam generator, reducing the overcooling effect and its subsequent effect on core reactivity. Failure of a MSIV to close is not required to be considered by the original license basis.

The limiting case for the containment analysis is the Large Break LOCA event. The pressurization of the reactor building due to the mass and energy from the blowdown of a ruptured steam line inside the reactor building does not establish the design basis of the MSIVs because of the small rate of mass and energy addition compared to a Large Break LOCA.

Since the pressurization of the reactor building by the main steam line break is not a limiting issue, the analysis conservatively maximizes the offsite dose by assuming the break occurs in the steam line outside the reactor building, but upstream of an MSIV. Although a break at this location is highly improbable, it serves to provide a direct path to the environment for any activity in the steam generators and leads to a complete blowdown of one steam generator. In addition, the analysis assumes that offsite power remains available to power the reactor coolant pumps,

APPLICABLE SAFETY ANALYSES (continued)

maximizing the overcooling effect and its subsequent effect on core reactivity. The main steam line break analysis verifies the effects of a double-ended guillotine steam line break at full power to ensure adequate margin to safety is maintained, consistent with the original license basis. The SAR does not analyze a feedwater line break.

The MSIVs serve a closing safety function. In MODE 1 the MSIVs satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3). Although no licensing basis accidents or transients relating to the function of the MSIVs exist in other modes, the MSIVs are conservatively considered to satisfy Criterion 4 of 10 CFR 50.36 in MODEs 2 and 3.

LCO

This LCO requires that the MSIV in each steam line be OPERABLE. For an MSIV to be considered OPERABLE, the isolation time must be within limits and the MSIV must close on an isolation actuation signal when required.

This LCO provides assurance that the MSIVs will perform their design safety function to isolate an SLB.

APPLICABILITY

The MSIVs must be OPERABLE to provide isolation of potential main steam line breaks in MODES 1, 2, and 3, when there is significant mass and energy in the RCS and steam generators.

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 are depressurized and the MSIVs are not required for isolation of potential main steam line breaks.

ACTIONS

A.1

With one or more MSIVs inoperable in MODE 1 or 2, action must be taken to restore the component to OPERABLE status within 24 hours. Some repairs can be made to the MSIV with the unit hot. The 24 hour Completion Time is reasonable, considering the probability of an accident that would require actuation of the MSIVs occurring during this time interval. Although not credited, the turbine throttle valves may be available to provide isolation for some postulated accidents.

ACTIONS (continued)

A.1 (continued)

The main steam and feedwater systems do not provide a direct path from the reactor building atmosphere to the environment. Therefore, the Completion Time is reasonable, and provides for diagnosis and repair of many MSIV problems, thereby avoiding unnecessary shutdown.

B.1

If the Required Action and associated Completion Time of Condition A are not met, the unit must be placed in MODE 3 within the next 12 hours. The Completion Time is reasonable, based on operating experience, to reach MODE 3.

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 MODE 3, the inoperable MSIV(s) 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.

The main steam and feedwater systems do not provide a direct path from the reactor building atmosphere to the environment. Therefore, the Completion Time is reasonable, and provides for diagnosis and repair of many MSIV problems, thereby avoiding unnecessary shutdown.

Inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but 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 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 Required Actions and associated Completion Times of Condition C are not 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 MODE 4 within 24 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from MODE 3 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 as specified in the Inservice Testing Program. The MSIV isolation time is assumed in the accident and reactor building analyses. This Surveillance is normally performed prior to returning the unit to power operation, e.g., during MODE 3, following a refueling outage, because the MSIVs should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power.

The Frequency for this SR is in accordance with the Inservice Testing Program.

This test is normally conducted in MODE 3, with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows delaying testing until MODE 3 in order to establish conditions consistent with those under which the acceptance criterion was generated.

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 unit to operation following a refueling outage. The Frequency of MSIV testing is every 18 months. The 18 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 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The first Note allows entry into and operation in MODE 3 prior to performing the SR. This allows delaying testing until MODE 3 in order to establish conditions consistent with those under which the acceptance criterion was established.

SR 3.7.2.2 is also modified by a second Note which indicates that the automatic closure capability is not required to be met when SG pressure is < 750 psig. At < 750 psig, the main steam line isolation Function of EFIC may be disabled to prevent automatic actuation on low steam generator pressure during a unit shutdown.

REFERENCES

1. SAR, Section 14.2.
2. SAR, Section 7.1.4.
3. 10 CFR 50.36.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves

BASES

BACKGROUND

The main feedwater isolation valves (MFIVs), Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves isolate main feedwater (MFW) flow to the secondary side of the steam generators. Closing the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside the reactor building and reducing the cooldown effects for SLBs.

The MFIVs close on receipt of a main steam line isolation (MSLI) signal as described in LCO 3.3.11, “Emergency Feedwater Initiation and Control (EFIC) System Instrumentation.” EFIC maintains the Low Load Feedwater Control Valves and Startup Feedwater Control Valves closed by sending a signal to the Rapid Feedwater Reduction (RFR) circuit of the Integrated Control System (ICS). The Main Feedwater Block Valves are independently closed by a signal from the Reactor Protection System (RPS) upon a reactor trip. The MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves can also be closed manually.

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves is established by the analysis for the SLB as discussed in SAR Section 14.2.2.1 (Ref. 1).

Failure of an MFIV, and an associated Main Feedwater Block Valve, Low Load Feedwater Control Valve or Startup Feedwater Control Valve to close following an SLB, can result in additional mass being delivered to the steam generators, contributing to cooldown.

In MODES 1 and 2, the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves satisfy Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODE 3, the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves satisfy Criterion 4 of 10 CFR 50.36.

APPLICABLE SAFETY ANALYSES (continued)

With the exception of the MFIVs, the valves are non-Q and powered from non-vital sources. This is acceptable when crediting feedwater isolation during a SLB since off-site power is assumed to remain available during this event.

LCO

This LCO ensures that the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves will isolate MFW flow to the steam generators following a main steam line break.

All MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves are required to be OPERABLE. For an MFIV, Main Feedwater Block Valve, Low Load Feedwater Control Valve or Startup Feedwater Control Valve to be considered OPERABLE, the isolation times must be within limits and the valve must close on an isolation actuation signal when required.

Failure to meet the LCO requirements can result in a more severe cooldown transient and in additional mass and energy being released to the reactor building following an SLB inside the reactor building.

APPLICABILITY

The MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves must be OPERABLE in MODES 1, 2, and 3 to ensure that, in the event of an SLB, the amount of feedwater provided to the affected steam generator is limited. Their closure terminates normal feedwater flow to limit the overcooling transient and to limit the amount of energy that could be added to the reactor building in the case of a secondary system pipe break inside the reactor building.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves 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

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their 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 to allow repairs and, if unsuccessful, to isolate the flow path.

Inoperable MFIVs that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analyis remain valid. The 7 day Completion Time is reasonable in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one Main Feedwater Block Valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE associated MFIV and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

Inoperable Main Feedwater Block Valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

ACTIONS (continued)

C.1 and C.2

With one Low Load Feedwater Control Valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE associated MFIV and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

Inoperable Low Load Feedwater Control Valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable 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 and D.2

With one Startup Feedwater Control Valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE associated MFIV and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths.

Inoperable Startup Feedwater Control Valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

E.1

With two inoperable valves in the same flow path there may be no redundant system to operate automatically and perform the required safety function. Although the containment can be isolated with the failure to two valves in parallel in the same flow path, the double failure can be an indication of a common mode failure in the valves of this flow path and as such is treated the same as a loss of the isolation

ACTIONS (continued)

E.1 (continued)

capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. The 8 hour Completion Time is reasonable to isolate the affected flow path.

F.1 and F.2

If the Required Actions and associated Completion Times are 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 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

This SR verifies that the closure time of each MFIV, Main Feedwater Block Valve, Low Load Feedwater Control Valve and Startup Feedwater Control Valve is as specified in the Inservice Testing Program.

The MFIV, Main Feedwater Block Valve, Low Load Feedwater Control Valve and Startup Feedwater Control Valve isolation time is assumed in the accident and reactor building analyses. This Surveillance is normally performed prior to returning the unit to power operation, e.g., during MODE 3, following a refueling outage. The MFIVs, Main Feedwater Block Valves, Low Load Feedwater Control Valves and Startup Feedwater Control Valves are not tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR.

The Frequency for this SR is in accordance with the Inservice Testing Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.2

This SR verifies that each MFIV, Main Feedwater Block Valve, Low Load Feedwater Control Valve and Startup Feedwater Control Valve can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the unit to operation following a refueling outage.

The Frequency for this SR is every 18 months. The 18 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 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The first Note allows entry into and operation in MODE 3 prior to performing the SR. This allows delaying testing until MODE 3 in order to establish conditions consistent with those under which the acceptance criterion was established.

SR 3.7.3.2 is also modified by a second Note which indicates that the automatic closure capability is not required to be met when the steam generator pressure is < 750 psig. At < 750 psig, the main steam line isolation Function of EFIC may be disabled to prevent automatic actuation on low steam generator pressure during a unit shutdown.

REFERENCES

1. SAR, Section 14.2.2.1.

2. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.4 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, abnormalities, 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 3.5 μCi/gm (LCO 3.4.12, "RCS Specific Activity"). The thyroid dose conversion factors used in the calculation of DOSE EQUIVALENT I-131 are those identified in Section 1.1, “Definitions.”

Operating a unit at the allowable limits could result in a 2 hour exclusion area boundary (EAB) exposure of a small fraction of the 10 CFR 100 (Ref. 1) limits.

APPLICABLE SAFETY ANALYSES

For the purpose of determining a maximum allowable secondary coolant activity, the activity contained in the mass released following the rupture of a steam generator tube, a steam line break outside the reactor building and a loss of load incident were considered (Safety Evaluation Report for ANO-1 License Amendment No. 2, 1CNA057502, dated May 9, 1975 (Ref. 2)).

The whole body dose is negligible since any noble gases entering the secondary coolant system are continuously vented to the atmosphere by the condenser vacuum pumps. Thus, in the event of a loss of load incident or steam line break, there are only small quantities of these gases which would be released (Ref. 2).

The dose analysis performed to determine the maximum allowable reactor coolant activity assuming the maximum allowable primary to secondary leakage of 1 gpm as given in the Bases for LCO 3.4.13 indicated that the controlling accident to determine the allowable secondary coolant activity would be the rupture of a steam

APPLICABLE SAFETY ANALYSES (continued)

generator tube. For the loss of load incident with a loss of 205,000 pounds of water released to the atmosphere via the relief valves, the resulting thyroid dose at the I-131 dose equivalent activity limit of 0.17 μCi/gm would be 0.6 Rem with the same meteorological and iodine release assumptions used for the steam generator tube rupture as given in the Bases for LCO 3.4.13. For the less probable accident of a steam line break, the assumption is made that a loss of 10^6 pounds of water or the contents of one loop in the secondary coolant system occurs and is released directly to the atmosphere. Since the water will flash to steam, the total radioiodine activity is assumed to be released to the atmosphere. The resulting thyroid dose at the I-131 dose equivalent activity limit of 0.17 μCi/gm would be less than 28 Rem with the same meteorological assumptions used for the steam generator tube rupture and loss of load incident (Ref. 2).

In MODES 1 and 2, secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36 (Ref. 3). In MODES 3 and 4, secondary specific activity limits satisfy Criterion 4 of 10 CFR 50.36.

LCO

As indicated in the Applicable Safety Analyses, the specific activity limit in the secondary coolant system of ≤ 0.17 μCi/gm DOSE EQUIVALENT I-131 maintains the radiological consequences of a Design Basis Accident (DBA) significantly less than the Reference 1 guideline doses.

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, secondary specific activity is not a concern.

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 cannot be restored to within limits 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 3.7.4.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis assumptions. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the analysis assumptions are met. 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 100.11.

2. Safety Evaluation Report for ANO-1 License Amendment No. 2, 1CNA057502, dated May 9, 1975.

3. 10 CFR 50.36

B 3.7 PLANT SYSTEMS

B 3.7.5 Emergency Feedwater (EFW) System

BASES

BACKGROUND

The EFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System (RCS) upon the loss of normal feedwater supply. The EFW pumps take suction from the safety related condensate storage tank (QCST) (LCO 3.7.6, "Q Condensate Storage Tank (QCST)"), and pump to the steam generator secondary side through the EFW nozzles. The core decay 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 dump valves (ADVs). If the main condenser is available, steam may be released via the turbine bypass valves.

The EFW System includes one turbine driven EFW pump, and one safety grade motor driven EFW pump. Thus, diversity in motive power sources is provided for the EFW System. The turbine driven EFW pump receives steam from either of the two main steam headers, upstream of the main steam isolation valves (MSIVs).

The EFW System supplies a common header capable of feeding either or both steam generators. Either pump is sufficient to remove decay heat and cool the unit to decay heat removal (DHR) entry conditions. The EFW System initially receives a supply of water from the QCST. The assured safety grade source of water is supplied by the Service Water System (SWS). Valves on the supply piping are manually opened to transfer the water supply from the QCST to the SWS. Water can be supplied from other sources by manually aligning nonsafety grade condensate storage tanks to the EFW pump suction.

The EFW System is capable of supplying feedwater to the steam generators, if required, during normal unit startup and shutdown evolutions, and during hot standby conditions. However, EFW does not provide a normal source of feedwater during these conditions. The normal supplement to the main feedwater system under these conditions is provided by the auxiliary feedwater system.

The EFW actuates automatically (e.g., on loss of main feedwater pumps, low steam generator level, low steam generator pressure, or loss of four reactor coolant pumps) as described in LCO 3.3.11, “Emergency Feedwater Initiation and Control (EFIC) System Instrumentation.”

The EFW System is discussed in the SAR, Sections 7.1.4 and 10.4.8 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The EFW System is sized to prevent exceeding 110% RCS design pressure for a specified loss of feedwater scenario (Ref. 3).

The design basis of the EFW System is to supply water to the steam generators to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure.

The EFW System design is such that it can perform its function with only one EFW train available.

In MODES 1 and 2, the EFW System satisfies Criterion 3 of 10 CFR 50.36 (Ref. 4). In MODE 3 and MODE 4 when steam generator(s) are relied upon for heat removal, the EFW System satisfies Criterion 4 of 10 CFR 50.36.

LCO

This LCO provides assurance that the EFW System will perform its design function to mitigate the consequences of events that could result in overpressurization of the reactor coolant pressure boundary. Two independent trains are required to be OPERABLE to ensure the availability of residual heat removal capability.

For both EFW trains to be considered OPERABLE, the components and flow paths are required to be capable of providing EFW flow to both steam generators. This requires that the turbine driven EFW pump be OPERABLE with two steam supplies (one from each of the main steam lines upstream of the MSIVs) and capable of supplying EFW flow to the steam generators. The safety grade motor driven EFW pump is also required to be OPERABLE and capable of supplying EFW flow to the steam generators. The piping, valves, instrumentation, and controls in the required flow paths must also be OPERABLE. The primary and secondary sources of water to the EFW System are required to be OPERABLE. The associated flow paths from the EFW System primary and secondary sources of water to both EFW pumps also are required to be OPERABLE.

The LCO is modified by a Note indicating that only one EFW train, which includes the motor driven EFW pump, 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 turbine driven EFW pump.

APPLICABILITY

In MODES 1, 2, and 3, the EFW System is required to be OPERABLE in order to function in the event that the main feedwater is lost. In addition, the EFW System is required to supply enough makeup water to replace the steam generator secondary inventory lost as the unit cools to MODE 4 conditions.

In MODE 4, the EFW System must be OPERABLE when the steam generators are relied upon for decay heat removal since EFW is the safety related source of feedwater to the steam generators. In MODE 4, the steam generators are normally used for heat removal until the DHR System is in operation.

In MODES 5 and 6, the steam generators are not used for DHR and the EFW System is not required.

ACTIONS

A.1

With one of the two steam supplies to the turbine driven EFW pump inoperable, or if the turbine driven EFW pump is inoperable in MODE 3 immediately following refueling, action must be taken to restore the steam supply to OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of a steam supply to the turbine driven EFW pump, the 7 day Completion Time is reasonable since there is a redundant steam line for the turbine driven pump.

b. For the inoperability of the turbine driven EFW pump 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. For both the inoperability of a steam supply line to the turbine driven pump and an inoperable turbine driven EFW pump while in MODE 3 immediately following a refueling, the 7 day Completion Time is reasonable due to the availability of the redundant OPERABLE motor driven EFW pump; and due to the low probability of an event requiring the use of the turbine driven EFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required EFW components to be inoperable during any continuous failure to meet this LCO.

ACTIONS (continued)

A.1 (continued)

The 10 day Completion Time provides a limitation on the time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

Condition A is modified by a Note which limits the applicability of the Condition to when the unit has not entered MODE 2 following a refueling. Condition A allows one EFW 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 required EFW trains (pump or flow path) is inoperable, 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 the turbine driven EFW pump. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the EFW System, time needed for repairs, and the low probability of an event requiring EFW occurring during this time period. The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required EFW components to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation on the time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

With the Required Action and associated Completion Time of Condition A or B not 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 18 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.

ACTIONS (continued)

D.1

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until at least one EFW train is restored to OPERABLE status.

With both 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 unit into a less safe condition.

E.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 EFW train inoperable, action must be taken to immediately 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. Correct alignment for automatic valves may be other than the post-accident position provided the valve is otherwise OPERABLE. 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 Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each EFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that EFW pump performance has not degraded below the established acceptance criteria during the cycle. Flow and differential head are indicators of pump performance required by Section XI of the ASME Code (Ref. 5). Because it is undesirable to introduce cold EFW into the steam generators while they are operating, this test may be performed on a test flow path.

This test 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, Section XI (Ref. 5) satisfies this requirement.

This SR is modified by a Note indicating that the SR may be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test.

SR 3.7.5.3

This SR verifies that EFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an Emergency Feedwater Initiation and Control (EFIC) System signal by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. Each automatic valve is also verified to be capable of manual operation by over-riding the actuation signal. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is also acceptable based on operating experience and design reliability of the equipment.

This SR is modified by a Note which states that the SR is not required to be met in MODE 4 when the steam generator is being relied upon for heat removal. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required EFW pump.

SR 3.7.5.4

This SR verifies that each EFW pump starts in the event of any accident or transient that generates an EFIC signal. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4 (continued)

performed with the reactor at power. This SR is modified by a Note which states that the SR is not required to be met in MODE 4 when the steam generator is being relied upon for heat removal. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required EFW pump.

SR 3.7.5.5

This SR ensures that the EFW system is properly aligned by verifying the position of manual valves in the flow paths to each steam generator prior to entering MODE 2 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 the EFW System during a subsequent shutdown. The Frequency is reasonable in view of other administrative controls, such as SR 3.7.5.1, to ensure that the flow paths are OPERABLE. To further ensure EFW System alignment, flow path OPERABILITY is verified, following extended outages to determine no misalignment of manual valves has occurred. This SR ensures that the flow path from the QCST to the steam generator is properly aligned.

SR 3.7.5.6

This SR ensures that the EFW flowpath to each steam generator is open and that water reaches the steam generators from the EFW System. This test is performed during shutdown to minimize thermal cycles to the emergency feedwater nozzles on the steam generator due to the lower temperature of the emergency feedwater. The motor-driven EFW pump is specified because of its availability at the low steam generator pressure conditions that exist in the shutdown condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. SAR, Section 7.1.4.
2. SAR, Section 10.4.8.
3. NRC Letter dated January 12, 1981, (1CNA018103).
4. 10 CFR 50.36.
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.6 Q Condensate Storage Tank (QCST)

BASES

BACKGROUND

The condensate storage tank (QCST) provides a source of demineralized water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The QCST provides the preferred source of water to the Emergency Feedwater (EFW) System (LCO 3.7.5, “Emergency Feedwater (EFW) System”).

Because the QCST is the normally aligned source to EFW, it is designed to withstand earthquakes and other natural phenomena, and a portion is protected from missiles that might be generated by natural phenomena. The QCST is designed as Seismic Category I to ensure availability of the initial EFW supply. Feedwater is also available from alternate sources.

A description of the QCST is found in the SAR, Section 10.4.8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The QCST provides the initial source of cooling water to remove decay heat and cool down the unit following any event with a loss of normal feedwater.

The T41B CST is seismically qualified and a portion of the tank is protected from tornado missiles. The protected volume of water in the tank can provide a source of EFW for both units for at least 30 minutes. Thirty minutes is adequate for the operators to manually switch the EFW suction alignment to the service water system (SWS), if required. The SWS provides the assured source of cooling water.

The QCST satisfies Criterion 4 of 10 CFR 50.36 (Ref. 2).

LCO

The protected volume of water in the tank can provide a source of emergency feedwater (EFW) for both units for at least 30 minutes. Thirty minutes is adequate for the operators to manually switch the EFW suction alignment to the service water system (SWS), if required. The SWS provides the assured source of cooling water.

The volume requirements for the CST are based on the EFW systems of both units being aligned to T41B simultaneously or only Unit 1 being aligned. The minimum volume requirements are sufficient to support several hours of cooling flow for both

LCO (continued)

units. During this time, the need for EFW will be determined. Alignment to available water sources will be performed as necessary to ensure adequate heat removal is maintained. The volume requirements are nominal values. In the conversion of the required volumes to indicated level, instrument uncertainty need not be applied.

APPLICABILITY

In MODES 1, 2, 3, and 4 when a steam generator is being relied upon for heat removal, the QCST is required to be OPERABLE.

In MODE 4 when a steam generator is not being relied upon for heat removal, and in MODES 5 and 6, the QCST is not required because the EFW System is not required.

ACTIONS

A.1 and A.2

As an alternative to unit shutdown, the OPERABILITY of the backup water supply 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 the flow paths from the backup supply to the EFW pumps and availability of the required volume of water in the backup supply. The QCST must be restored to OPERABLE status within 7 days because the backup supply may be performing this function in addition to its normal functions. 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 water from the QCST.

B.1 and B.2

If the Required Action and associated Completion Times are 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.

ACTIONS (continued)

B.1 and B.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.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the QCST contains the required 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 QCST 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 QCST levels.

The volume requirements for the CST are based on the EFW systems of both units being aligned to T41B simultaneously or only Unit 1 being aligned. The minimum volume requirements are sufficient to support several hours of cooling flow for both units. During this time, the need for EFW will be determined. Alignment to available water sources will be performed as necessary to ensure adequate heat removal is maintained. The volume requirements are nominal values. In the conversion of the required volumes to indicated level, instrument uncertainty need not be applied.

REFERENCES

1. SAR, Section 10.4.8.

2. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.7 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a transient or Design Basis Accident (DBA). During normal operation and normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related portion is covered by this LCO.

The SWS consists of two independent but interconnected, 100% capacity safety related cooling water loops. Three 100% capacity pumps are provided to supply the two loops. Each loop consists of a pump, piping, valving, sluice gates and instrumentation. The pumps, sluice gates and valves are remote manually aligned. In the unlikely event of a loss of coolant accident (LOCA) essential valves are aligned to their post accident positions upon receipt of an engineered safeguards actuation signal. The SWS provides cooling directly to required plant equipment. The system is also the assured safety related source of water to the emergency feedwater pumps, and can also provide a source of makeup water to the emergency cooling pond, and to the spent fuel pool.

The requirements of the SWS for cooling water are more severe during normal operation (at full power) than under accident conditions. Normal operation requires at least two of the three service water pumps, and the pumps in operation are periodically rotated. Normal operation also includes the addition of a biocide during the reactor building emergency cooler surveillance, when the water temperature is between 60°F and 80°F, to prevent biological fouling of the coolers. This water temperature range provides conditions under which Asian clams can spawn and produce larvae which could pass through SWS strainers.

Additional information about the design and operation of the SWS, along with a list of the components served, is presented in the SAR, Section 9.3 (Ref. 1). The principal safety related function of the SWS is the transfer of heat from the reactor and safety related components to the heat sink.

APPLICABLE SAFETY ANALYSES

The primary safety function of the SWS is for one SWS loop, in conjunction with the Low Pressure Injection System and the Reactor Building Cooling System, (reactor building spray, reactor building air coolers, or a combination) to remove core decay heat following a design basis LOCA, as discussed in the SAR, Sections 6.2 and 6.3 (Refs. 2 and 3, respectively).

APPLICABLE SAFETY ANALYSES (continued)

The SWS is designed to perform its function with a single failure of any active component, assuming loss of offsite power.

The SWS 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 SAR, Section 9.5 (Ref. 4). The time required for this evolution is a function of the number of DHR loops that are operating.

The SWS is also required to transfer heat from the diesel generators (DGs).

In MODES 1 and 2, the SWS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODES 3 and 4, the SWS satisfies Criterion 4 of 10 CFR 50.36.

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.

For an SWS loop to be considered OPERABLE, it must have:

a. One OPERABLE pump; and

b. The associated piping, valves, sluice gates, and instrumentation and controls required to perform the safety related function OPERABLE.

In addition to the requirements above, for both SWS loops to be considered OPERABLE the required SW pumps must be powered from independent essential buses, to provide redundant and independent flow paths.

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. Therefore, the SWS is 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. Although the systems it supports may be required to be OPERABLE, the SWS is not required to meet the same OPERABILITY requirements in MODES 5 and 6 as it must in MODES 1, 2, 3, and 4. The definition of OPERABILITY embodies the principle that a system can perform its function(s) only if all necessary support systems are capable of performing their related support functions. If the supported system is capable of performing its safety function without reliance on the SWS, then the SWS is not required to be OPERABLE. Similarly, operation with the SWS in a less than fully qualified state is acceptable provided an assessment has been performed to determine that the supported system remains capable of performing its safety function.

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 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 DG. 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 Required Action and associated Completion Time are not 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

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 the existence of procedural controls governing valve operation, and ensures correct valve positions.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.1 (continued)

This SR is modified by a Note indicating that the isolation of components or systems supported by the SWS does not affect the OPERABILITY of the SWS. However, such isolation may render those components inoperable.

SR 3.7.7.2

The SR verifies proper automatic operation of the SWS valves. The SWS is a normally operating system that cannot be fully actuated as part of the normal testing. This SR is not required for valves that are locked, sealed, or otherwise secured in position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and on 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 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR requires verification that the normally operating SWS pumps (A and C) automatically restart following restoration of power to the respective bus. In addition, the B SWS pump, normally in the standby condition, must be verified to start to support each SWS train for which it is expected to be aligned upon associated ES actuation (with time delay) with simulated failure of the normally operating pump for that train.

The 18 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 an 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. SAR, Section 9.3.
2. SAR, Section 6.2.
3. SAR, Section 6.3.
4. SAR, Section 9.5.
5. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.8 Emergency Cooling Pond (ECP)

BASES

BACKGROUND

The ECP provides a shared heat sink for removing operating heat from safety related components if the heat sink provided by the Dardanelle Reservoir is unavailable. This is done utilizing the Service Water System (SWS).

The ECP is a portion of the complex of water sources which fulfill the ultimate heat sink requirements for ANO. This complex includes the necessary retaining structures and the piping connecting the sources with, but not including, the SWS intake structure, as discussed in the SAR, Section 9.3 (Ref. 1). The principal function of the ECP is dissipation of residual heat after a reactor shutdown.

The basic performance requirements are that a 30 day supply of water be available for both units, and that the design basis temperatures of safety related equipment not be exceeded. Additional information on the design and operation of the system can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The ECP is the sink for heat removal from the reactor core following an abnormality in which the unit is cooled down and placed on decay heat removal following a loss of the Dardanelle Reservoir inventory which would be considered a single failure.

The operating limits are based on conservative heat transfer analyses for the worst case initial conditions that could be present considering a Unit 2 Design Basis Accident concurrent with a normal shutdown of Unit 1 and a loss of the Dardanelle Reservoir water inventory. Reference 1 provides the details of the assumptions used in the analysis. The minimum ECP requirements take into account: water loss from evaporation due to heat load and climatological conditions, fire pump usage, ECP bottom irregularities, suction pipe level at the ECP, and operator action in transferring the SWS from the Dardanelle Reservoir. Operator action is credited in the inventory analysis during the transfer of the SWS to the ECP. Specifically, pump returns are transferred to the ECP shortly after the Dardanelle Reservoir loss of inventory event begins and pump suctions are transferred later in the event depending on pump bay level. In the time frame between the transfer of the returns and suctions to the ECP, lake water is pumped into the ECP, increasing level. This additional water is required, along with that maintained in the ECP, to ensure a 64.5 inch depth, which corresponds to a 30 day supply of cooling water. The ECP is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water.

The ECP satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3).

LCO

The ECP is a backup system that is required to be OPERABLE to support the SWS. To be considered OPERABLE, the ECP must contain 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 event without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the ECP initial temperature should not exceed 100°F, and the volume of water should not fall below 70 acre-feet during normal unit operation.

APPLICABILITY

In MODES 1, 2, 3, and 4, the ECP is a backup system that is required to support the OPERABILITY of the equipment serviced by the SWS and is required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the ECP are determined by the systems it supports. Although the systems it supports may be required to be OPERABLE, the ECP is not required to meet the same OPERABILITY requirements in MODES 5 and 6 as it must in MODES 1, 2, 3, and 4. The definition of OPERABILITY embodies the principle that a system can perform its function(s) only if all necessary support systems are capable of performing their related support functions. If the supported system is capable of performing its safety function without reliance on the ECP, then the ECP is not required to be OPERABLE. Similarly, operation with the ECP in a less than fully qualified state is acceptable provided an assessment has been performed to determine that the supported system remains capable of performing its safety function. It is important to recognize that single failure criteria is not applicable in MODES 5 and 6. Therefore, the availability of Lake Dardanelle as a heat sink during periods of ECP unavailability may be acceptable provided the probability of a loss of lake and the time to respond to a loss of lake event are considered when planning ECP unavailability periods.

ACTIONS

A.1 and A.2

If the ECP 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR (together with SR 3.7.8.3 and SR 3.7.8.4) verifies that adequate long term (30 days) cooling inventory is available. 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 ECP level during the applicable MODES. This SR verifies that the ECP indicated water level is ≥ 5.2 ft.

SR 3.7.8.2

This SR provides assurance that the heat sink for the SWS can dissipate the maximum accident or normal heat loads for 30 days following the design basis event. The temperature, measured at the point of discharge from the ECP, is considered a conservative average of total ECP conditions since solar gain, wind speed, and thermal current effects throughout the ECP will essentially be at equilibrium conditions under initial stagnant conditions. The 24 hour Frequency is based on operating experience related to the trending of the ECP temperature during the applicable MODES. This SR verifies that the ECP average water temperature at the point of discharge from the ECP (i.e., SWS suction) is ≤ 100°F.

This SR is modified by a Note indicating that the temperature monitoring is required to be performed only during the summer months (i.e., June 1 to September 30). During other periods of the year, the ECP temperature will not have the potential to reach the temperature limit.

SR 3.7.8.3

This SR (together with SR 3.7.8.1 and 3.7.8.4) verifies that adequate inventory exists to support long term (30 days) cooling. Soundings are performed to ensure the water volume is within limits and that the indicated water level is indicative of an equivalent water volume for accident mitigation. The 12 month Frequency reflects the gradual pace of degradation of the physical properties of the ECP.

SR 3.7.8.4

This SR (together with SR 3.7.8.1 and 3.7.8.3) verifies that adequate inventory exists to support long term (30 days) cooling. Visual inspections of the loose stone (riprap) placed on the banks of the ECP and of the concrete slab spillway are performed to ensure any physical degradation is within acceptable limits to enable the ECP to fulfill its safety function. An engineering evaluation is performed of any apparent changes in visual appearance or other abnormal degradation to determine OPERABILITY. The 12 month Frequency reflects the gradual pace of degradation of the physical properties of the ECP.

REFERENCES

1. SAR, Section 9.3.

2. Regulatory Guide 1.27, Rev. 1, “Ultimate Heat Sink for Nuclear Power Plants,” March 1974.

3. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.9 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The CREVS is a shared system which provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity.

The CREVS consists of two independent, redundant, fan and filter assemblies. Each fan circulates control room air through a filter train consisting of a roughing filter, a high efficiency particulate air (HEPA) filter, and a charcoal adsorber. For control room pressurization, each train provides additional outside air filtered through a four inch bed of charcoal adsorber.

The CREVS is an emergency system. Upon receipt of a unit specific high radiation signal, the control room envelope is isolated, the associated unit's normal control room ventilation system is shutdown, and the associated unit's CREVS is started. The control room envelope is maintained sufficiently leak tight to minimize unfiltered air inleakage. The CREVS operation is discussed in the SAR, Section 9.7 (Ref. 1).

The CREVS is designed to maintain the control room for 30 days of continuous occupancy after a Design Basis Accident (DBA), without exceeding a 5 rem whole body dose or its equivalent to any part of the body.

APPLICABLE SAFETY ANALYSES

The shared CREVS components are arranged in two safety related ventilation trains, which ensure an adequate supply of filtered air to all areas requiring access. The CREVS provides airborne radiological protection for the control room operators for the design basis loss of coolant accident fission product release and for a fuel handling accident.

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.

In MODES 1 and 2, and during the movement of irradiated fuel assemblies, the CREVS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODES 3 and 4, the CREVS satisfies Criterion 4 of 10 CFR 50.36.

LCO

Two CREVS trains are required to be OPERABLE to ensure that at least one is available if a single failure disables the other train. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a large radioactive release.

For a CREVS train to be considered OPERABLE, the CREVS train must include the associated:

a. OPERABLE fan;

b. OPERABLE HEPA filter and charcoal adsorber; and

c. OPERABLE ductwork and dampers sufficient to maintain air circulation and provide adequate makeup air flow.

In addition, the control room envelope, including the integrity of the walls, floors, ceilings, ductwork, and access doors, must be maintained within the assumptions of the design analysis.

The LCO is modified by two Notes. Note 1 allows the control room 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 control room isolation is indicated. Note 2 requires that one CREVS train be capable of automatic actuation. The other train may be started manually, on failure of the first train. If the control room is isolated and operating in the emergency recirculation mode, automatic actuation of the CREVS train is no longer required.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREVS must be OPERABLE to ensure that the control room will remain habitable during and following a DBA.

During movement of irradiated fuel assemblies, the CREVS must be OPERABLE to cope with a release due to a fuel handling accident.

ACTIONS

A.1

With one CREVS train inoperable due to other than the loss of capability for automatic actuation on a high radiation signal, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the control room radiation 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. If automatic actuation on high radiation is lost, the Conditions and Required Actions of LCO 3.3.16 provide sufficient actions to ensure continued safe operation.

B.1 and B.2

If the control room boundary is inoperable in MODES 1, 2, 3, and 4, the CREVS trains cannot perform their intended functions. Actions must be taken to restore an OPERABLE control room boundary within 24 hours. During the period that the control room boundary is inoperable, appropriate compensatory measures (consistent with the intent of GDC 19) should be utilized to protect control room operators from potential hazards such as radioactivity, toxic chemicals, smoke, temperature and relative humidity, and physical security. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the Condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possible repair, and test most problems with the control room boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4 if the inoperable CREVS train or control room boundary 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 and without challenging unit systems.

ACTIONS (continued)

D.1 and D.2

During movement of irradiated fuel assemblies, if the Required Action and associated Completion Time of Condition A are not met, the OPERABLE CREVS train must immediately be placed in the emergency recirculation mode. This action ensures that no failures preventing automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend movement of irradiated fuel assemblies since this is an activity that could release radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes the accident risk. This does not preclude movement of fuel to a safe position.

E.1

During movement of irradiated fuel assemblies, when two CREVS trains are inoperable, action must be taken immediately to suspend movement of irradiated fuel assemblies since this is an activity that could release radioactivity that could enter the control room. This places the unit in a condition that minimizes the accident risk. This does not preclude movement of fuel to a safe position.

F.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4 for reasons other than an inoperable control room boundary (i.e., Condition B), the CREVS may not be capable of performing the intended function and a loss of safety function has occurred. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

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. This test is conducted on alternating trains semi-monthly by initiating flow through the HEPA filters and charcoal adsorbers. The CREVS is designed without heaters and need only be operated for ≥ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the known reliability of the equipment and two train redundancy available.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

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 efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.9.3

This SR verifies that the CREVS automatically isolates the Control Room within 10 seconds and switches into a recirculation mode of operation with flow through the HEPA filters and charcoal adsorber banks on an actual or simulated actuation signal. The Frequency of 18 months is consistent with the guidance provided in Regulatory Guide 1.52 (Ref. 3).

SR 3.7.9.4 and SR 3.7.9.5

These SRs verify the ability of the CREVS to provide outside air at a flow rate consistent with their safety function to protect the operator from radiological exposure by minimizing unfiltered air in-leakage in the event of an accident. Many factors must be taken into account to determine the overall expected dose consequences for control room personnel during various off-normal events. The CREVS makeup airflow and filter efficiency are two of the factors that must be considered. Makeup airflow, which is filtered outside air, is drawn into the control room recirculated airflow to pressurize the control room in order to reduce the potential for unfiltered in-leakage. The flow verification ensures that an assumed amount of makeup air is available to account for boundary leak paths. The flowrate verification is consistent with SRP Section 6.4 (Reference 4) for those control rooms having a design makeup rate of $\geq$ 0.5 volume changes per hour. Due to design variations between the filter trains, the acceptance criteria for each train are different. SR 3.7.9.4 verifies VSF-9 makeup air flow accounting for a separate makeup air filter in the acceptance criteria. SR 3.7.9.5 verifies 2VSF-9 makeup air flow which is based on expected flow rates through the flow path. The Frequency of 18 months is considered adequate to detect any degradation of the outside air flow rate before it is reduced to a point at which sufficient pressurization will not occur.

REFERENCES

1. SAR, Section 9.7.

2. 10 CFR 50.36.

3. Regulatory Guide 1.52, “Design, Testing, and Maintenance Criteria for Post Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants,” Rev. 2, March 1978.

4 Standard Review Plan, Section 6.4, "Control Room Habitability System," Rev. 2, July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Air Conditioning System (CREACS)

BASES

BACKGROUND

The CREACS provides temperature control for the control room following isolation of the control room.

The CREACS 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, dampers, and instrumentation also form part of the system. During operation, the CREACS maintains the temperature in a range consistent with personnel comfort and long term equipment operation. The CREACS is a subsystem providing air temperature control for the control room.

The CREACS is an emergency system. On detection of high radiation, the control room envelope is isolated, the normal control room ventilation system is shut down, and the CREACS is started. A single train will provide the required temperature control. The CREACS operation to maintain control room temperature is discussed in the SAR, Section 9.7 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CREACS is to maintain control room temperature for 30 days of continuous occupancy.

The CREACS components are arranged in redundant, safety related trains. A single active failure of a CREACS component does not impair the ability of the system to perform as designed. The CREACS is designed in accordance with Seismic Category I requirements. The CREACS 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 a habitable environment and equipment OPERABILITY.

In MODES 1 and 2, and during movement of irradiated fuel assemblies, the CREACS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODES 3 and 4, the CREACS satisfies Criterion 4 of 10 CFR 50.36.

LCO

Two independent and redundant trains of the CREACS 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 control room temperature exceeding limits in the event of an accident.

For a CREACS train to be considered OPERABLE, the individual components that are necessary to maintain control room temperature must be OPERABLE. These components include the cooling coils, condensing units, and associated temperature control instrumentation. In addition, the CREACS must be capable of maintaining air circulation.

APPLICABILITY

In MODES 1, 2, 3, and 4, and during movement of irradiated fuel assemblies, the CREACS must be OPERABLE to ensure that the control room temperature will not exceed habitability and equipment OPERABILITY requirements following isolation of the control room.

ACTIONS

A.1

With one CREACS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CREACS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a failure in the OPERABLE CREACS train could result in a loss of CREACS 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 alternate nonsafety related cooling means that are available.

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, 3, or 4, if the Required Action and associated Completion Time of Condition A are not 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 without challenging unit systems.

C.1 and C.2

During movement of irradiated fuel, if the Required Action and associated Completion Time of Condition A are not met, the OPERABLE CREACS train must be placed in operation immediately. This action ensures that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that could release radioactivity that might require the isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1

During movement of irradiated fuel assemblies, with two CREACS trains inoperable, action must be taken to immediately suspend activities that could release radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

E.1

If both CREACS trains are inoperable in MODE 1, 2, 3, or 4, a loss of safety function has occurred, and LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1 and SR 3.7.10.2

These SRs, in conjunction with periodic preventative maintenance activities, provide verification that the CREACS will maintain the control room temperature within acceptable bounds. SR 3.7.10.1 is performed on a staggered basis with one train being tested every two weeks. The Frequencies (31 days and 18 months) are appropriate as periodic preventative maintenance activities are routinely performed and significant degradation of the CREACS is not expected over these time periods.

REFERENCES

1. SAR, Section 9.7.

2. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.11 Penetration Room Ventilation System (PRVS)

BASES

BACKGROUND

The PRVS filters air from the penetration areas in the event of penetration leakage from the reactor building during a loss of coolant accident (LOCA).

The PRVS consists of two independent, redundant trains. Each train consists of a prefilter, a high efficiency particulate air (HEPA) filter, and an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, dampers, and instrumentation also form part of the system. The system initiates filtered ventilation of the penetration rooms following receipt of an engineered safeguards actuation system (ESAS) signal.

Following a LOCA, an ESAS signal starts the lead PRVS and if proper flow is not achieved within 20 seconds, the lead system is automatically stopped and 5 seconds later the standby system starts. Upon receipt of the ESAS signal, normal air discharges from the area are isolated, and the air is discharged through the system filters. The prefilters remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The PRVS is discussed in the SAR, Sections 6.5 and 14.2.2.5 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the PRVS is established by the LOCA. The system provides filtration for the most likely location of reactor building leakage, i.e., at the penetrations. The analysis of the effects and consequences of a LOCA is presented in Reference 2.

In MODES 1 and 2, the PRVS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3). In MODES 3 and 4, the PRVS satisfies Criterion 4 of 10 CFR 50.36.

LCO

Two redundant trains of the PRVS 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.

For a PRVS train to be considered OPERABLE, its associated:

a. Fan must be OPERABLE;

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

c. Required ductwork, and dampers must be OPERABLE.

The LCO is modified by a Note allowing the PRVS 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 PRVS negative pressure boundary isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the PRVS is required to be OPERABLE consistent with the OPERABILITY requirements of the reactor building.

In MODES 5 and 6, the PRVS is not required to be OPERABLE since the reactor building is not required to be OPERABLE.

ACTIONS

A.1

With one PRVS train inoperable, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the PRVS safety function. However, the overall reliability is reduced because a single failure in the OPERABLE PRVS train could result in loss of PRVS function.

The 7 day Completion Time is appropriate because the risk contribution is less than that of the reactor building (1 hour Completion Time), and this system is not a direct support system for the reactor building. 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.

ACTIONS (continued)

B.1

If the PRVS negative pressure boundary is inoperable, the PRVS trains cannot perform their intended functions. Actions must be taken to restore an OPERABLE PRVS negative pressure boundary within 24 hours. During the period that the PRVS negative pressure boundary is inoperable, appropriate compensatory measures (consistent with the intent, as applicable, of GDC 64 and 10 CFR Part 100) should be utilized to control and minimize the release of radioactive materials from the reactor building to the environment in post accident conditions. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the Condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possible repair, and test most problems with the PRVS negative pressure boundary.

C.1 and C.2

If the Required Action and the associated Completion Time are not met, or with both PRVS trains 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

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. The 31 day Frequency is based on known reliability of equipment and the two train redundancy available.

SR 3.7.11.2

This SR verifies that the required PRVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.11.3

This SR verifies that each PRVS train starts and operates on an actual or simulated actuation signal. The 18 month Frequency is consistent with the guidance provided in Regulatory Guide 1.52 (Ref. 4).

REFERENCES

1. SAR, Section 6.5.

2. SAR, Sections 14.2.2.5 and 14.2.2.6.

3. 10 CFR 50.36.

4. Regulatory Guide 1.52, “Design, Testing, and Maintenance Criteria for Post Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants,” Rev. 2, March 1978.

B 3.7 PLANT SYSTEMS

B 3.7.12 Fuel Handling Area Ventilation System (FHAVS)

BASES

BACKGROUND

The FHAVS filters airborne radioactive material from the area of the spent fuel pool following a fuel handling accident.

The FHAVS consists of portions of the normal Auxiliary Building Heating, Ventilation, and Air Conditioning System. The FHAVS consists of a single train which includes a supply fan, prefilter, high efficiency particulate air (HEPA) filter, activated charcoal adsorber section for removal of gaseous activity (principally iodines), and two exhaust fans. Ductwork, dampers, and instrumentation also form part of the system.

During operation, the exhaust from the fuel handling area is passed through the FHAVS exhaust filter and is discharged through the station vent stack.

The FHAVS is discussed in the SAR, Sections 9.7 and 14.2.2 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The FHAVS design basis is established by the fuel handling accident. The analysis of the fuel handling accident, given in Reference 2, credits the FHAVS for a reduction in the amount of airborne radioactive material released to the environment. The assumptions and the analysis are further discussed in Reference 2.

The FHAVS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3).

LCO

During movement of irradiated fuel, the FHAVS is required to be OPERABLE and operating.

For the FHAVS to be considered OPERABLE:

1. One exhaust fan must be OPERABLE;

2. HEPA filter and charcoal adsorber must not be excessively restricting flow, and must be capable of performing their filtration functions; and

3. Ductwork and dampers must be OPERABLE.

LCO (continued)

The FHAVS must be operating since it does not automatically start following a fuel handling accident. A supply fan may be operating, but is not required for FHAVS OPERABILITY.

APPLICABILITY

During movement of irradiated fuel assemblies in the fuel handling area, the FHAVS is always required to be OPERABLE and operating 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 which states 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 MODES 1, 2, 3, or 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.

A.1

When the FHAVS is inoperable or not in operation during movement of irradiated fuel assemblies in the fuel handling area, immediate action must be taken to preclude the occurrence of an accident. This is achieved by immediately suspending movement of irradiated fuel assemblies in the fuel handling area. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Periodic verification of the operation of the FHAVS assures immediate availability of filtration following a fuel handling accident. A 12 hour Frequency is sufficient, considering the system indications and alarms available to the operator for monitoring the FHAVS in the control room.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.2

This SR verifies that the required FHAVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

REFERENCES

1. SAR, Section 9.7.

2. SAR, Section 14.2.2.

3. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.13 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 SAR, Section 9.6.1.3, Reference 1. The Spent Fuel Pool Cooling and Cleanup System is given in the SAR, Section 9.4 (Ref. 2). The assumptions of the fuel handling accident are given in the SAR, Section 14.2.2.3 (Ref. 3).

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the spent fuel pool is an initial condition design parameter in the analysis of the fuel handling accident in the fuel handling building postulated by Regulatory Guide 1.25 (Ref. 4). A minimum water level of 23 feet above the top of the irradiated fuel assemblies seated in the storage racks (Regulatory Position C.1.c of Ref. 4) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 4) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the spent fuel pool water. The fuel pellet to cladding gap is assumed to contain 12% of the total fuel rod iodine inventory (Ref. 3).

The fuel handling accident analysis inside the fuel handling building is described in Reference 3. With a minimum water level of 23 feet above the top of the irradiated fuel assemblies seated in the storage racks, and a minimum decay time of 100 hours prior to fuel handling, the analysis demonstrates 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. 5).

The spent fuel pool water level satisfies Criterion 2 of 10 CFR 50.36 (Ref. 6).

LCO

The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required for fuel storage and movement within the 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.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

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 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.

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 3.7.13.1

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. FSAR, Section 9.6.1.3.
2. FSAR, Section 9.4.
3. FSAR, Section 14.2.2.3.

REFERENCES (continued)

4. Regulatory Guide 1.25.

5. 10 CFR 100.11.

6. 10 CFR 50.36

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND

As described in the Bases for LCO 3.7.15, "Spent Fuel Pool Storage," fuel assemblies are stored in the spent fuel pool racks in accordance with criteria based on initial enrichment and discharge burnup. Although the water in the spent fuel pool is normally borated to ≥ 1600 ppm, the criteria that limit the storage of a fuel assembly to specific rack locations are conservatively developed without taking credit for boron in the spent fuel pool water.

The spent fuel storage pool is divided into two separate and distinct regions as shown in SAR Figure 9-53 which, for the purpose of criticality considerations, are considered as separate pools. Region 1 is designed to accommodate new fuel with a maximum enrichment of 4.10 wt% U-235, or spent (irradiated) fuel regardless of the discharge fuel burnup. Region 2 is designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.15-1. Fuel assemblies not meeting the criteria of Figure 3.7.15-1 shall be stored in accordance with Specification 4.3.1.1.e.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978, NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. Thus, for accident conditions, the presence of soluble boron in the spent fuel pool water can be assumed as a realistic condition. For example, accident scenarios are postulated which could potentially increase the reactivity and reduce the margin to criticality. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the high density storage racks with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with LCO 3.7.15, "Spent Fuel Pool Storage." Prior to movement of an assembly, it is necessary to perform SR 3.7.15.1.

APPLICABLE SAFETY ANALYSES

Most accident conditions will not result in an increase in K_{eff} of the rack. Examples are the loss of cooling systems (reactivity decreases with decreasing water density) and dropping a fuel assembly on top of the rack (the rack structure pertinent for criticality is not deformed and the assembly has more that eight inches of water separating it from the active fuel in the rest of the rack which precludes interaction). However, accidents can be postulated which would increase reactivity such as inadvertent drop of an assembly between the outside periphery of the rack and the pool wall. Thus, for accident conditions, the presence of soluble boron in the storage pool water is assumed as a realistic initial condition.

The presence of 1600 ppm boron in the pool water will decrease reactivity by approximately 30% ΔK. Thus $K_{eff} \leq 0.95$ can be easily met for postulated accidents, since any reactivity increase will be much less than the negative worth of the dissolved boron.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36 (Ref. 4).

LCO

The specified concentration $\geq$ 1600 ppm of dissolved boron in the spent fuel pool conservatively preserves the assumption used in the analyses of the potential accident scenarios. 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, or cask loading pit (when the gate is open), until a complete 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

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.

ACTIONS (continued)

A.1, A.2.1, and A.2.2 (continued)

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. In addition, action must be immediately initiated to restore the spent fuel pool boron concentration to within its limit. An acceptable alternative is to immediately initiate performance of a spent fuel pool verification to ensure proper locations of the fuel since the last movement of fuel assemblies in the spent fuel pool. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. Either of these actions are acceptable, and once initiated must be continued until the action is completed. The immediate Completion Time for initiation of these actions reflects the importance of maintaining a controlled environment for irradiated fuel.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies that the concentration of boron in the spent fuel pool and cask loading pit is within the required limit. As long as this SR is met, the analyzed incidents are fully addressed. The 7 day Frequency for the pool is appropriate because no major replenishment of pool water is expected to take place over a short period of time.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978, NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. SAR, Section 14.2.2.3.

3. Safety Evaluation Report, Section 2.1.3, License Amendment No. 76, April 15, 1983.

4. 10 CFR 50.36.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pool Storage

BASES

BACKGROUND

The spent fuel assembly storage facility is designed to store either new (nonirradiated) nuclear fuel assemblies, or burned (irradiated) fuel assemblies in a vertical configuration underwater. The spent fuel pool is sized to store 968 fuel assemblies and is connected to a pit for loading shipping or dry fuel storage casks. The spent fuel storage cells are installed in parallel rows with center to center spacing of 10.65 inches in each direction. The cask configuration is in accordance with the cask venders Certificate of Compliance.

The spent fuel storage pool is divided into two separate and distinct regions as shown in SAR Figure 9-53 which, for the purpose of criticality considerations, are considered as separate pools. Region 1 is designed to accommodate new fuel with a maximum enrichment of 4.10 wt% U-235, or spent (irradiated) fuel regardless of the discharge fuel burnup. Region 2 is designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.15-1. Fuel assemblies not meeting the criteria of Figure 3.7.15-1 shall be stored in accordance with paragraph 4.3.1.1.e in SAR Section 4.3, Fuel Storage. The criticality considerations for the cask are the same as required for Region 1 of the spent fuel pool storage locations.

APPLICABLE SAFETY ANALYSES

Criticality of fuel assemblies in the spent fuel storage rack and casks is prevented by the design of the rack or cask, which limits fuel assembly interaction. This is done by fixing the minimum separation between assemblies and inserting neutron poison between assemblies in Region 1. Region 2 controls fuel assembly interaction by fixing the minimum separation between assemblies and by setting enrichment and burnup criterion to limit fissile materials. This is sufficient to maintain a k_{eff} of ≤ 0.95 for spent fuel of original enrichment of up to 4.10%. However, fuel assemblies to be stored in the spent fuel pool Region 2 which do not meet enrichment and burnup criterion must be stored in a checkerboard pattern to maintain a k_{eff} of 0.95 or less. In order to prevent inadvertent fuel assembly insertion into two adjacent storage locations, vacant spaces adjacent to the faces of any fuel assembly which does not meet the Region 2 burnup criteria (unrestricted) are physically blocked before any such fuel assembly is placed in Region 2 (Ref. 1). In addition, the area designated for checkerboard arrangement is divided from the normal storage in Region 2 by a row of vacant storage spaces (Ref. 2).

The spent fuel pool storage satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3).

LCO

The restrictions on the placement of fuel assemblies within the fuel pool, according to Figure 3.7.15-1 or equivalent cask criticality analysis, ensure that the k_{eff} of the spent fuel pool and cask loading pit will always remain $\leq$ 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. Fuel assemblies not meeting the enrichment and burnup criteria shall be stored in accordance with Specification 4.3.1.1.

In the event a checkerboard storage configuration is deemed necessary for a portion of Region 2, vacant spaces adjacent to the faces of any fuel assembly which does not meet the Region 2 burnup criteria (non-restricted) shall be physically blocked before any such fuel assembly may be placed in Region 2. This will prevent inadvertent fuel assembly insertion into two adjacent storage locations.

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in Region 2 of the spent fuel pool.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 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, in either case, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

When the configuration of fuel assemblies stored in the spent fuel pool is not in accordance with Figure 3.7.15-1, immediate action must be taken to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figure 3.7.15-1 or Specification 4.3.1.1.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Figure 3.7.15-1 in the accompanying LCO or Specification 4.3.1.1. For fuel assemblies in the unacceptable range of Figure 3.7.15-1, performance of the SR will ensure compliance with Specification 4.3.1.1.

REFERENCES

1. SAR, Section 9.6.2.

2. SER for ANO-1 License Amendment No. 76, Section 2.1 (0CNA048314), dated April 15, 1983.

3. 10 CFR 50.36.

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 alternates) and the onsite standby power sources (emergency diesel generators (DGs)). As required by SAR, Section 1.4, 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 Safeguards (ES) 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 DG.

Offsite power is supplied to the unit switchyard from the transmission network by five transmission lines. From the switchyard, two electrically and physically separated offsite circuits provide AC power, through either the Startup Transformers or the Unit Auxiliary Transformer, to the 4.16 kV ES buses. A detailed description of the offsite power network and the circuits to the Class 1E ES buses is found in the SAR, Chapter 8 (Ref. 2).

During typical on-line operation, power for unit equipment is provided from the Unit Auxiliary Transformer. When the unit is off-line, unit equipment is typically powered from a Startup Transformer or from the Unit Auxiliary Transformer back fed from the 500 kV switchyard. A unit trip (i.e., generator lockout) initiates an automatic transfer to an offsite power circuit (i.e., typically Startup Transformer No. 1). Startup Transformer No. 2 is normally not selected for automatic transfer since it is the backup for both Unit 1 and Unit 2. In the event of a loss of offsite power to the Startup Transformer, an undervoltage condition trips its associated bus feeder breakers. When the Startup Transformer bus feeder breakers open, the bus feeder breakers for the alternate Startup Transformer automatically close (if available) provided the generator lockout relays have not been reset. If the power source is transferred to Startup Transformer No. 2, sufficient loads are automatically shed to avoid a degraded voltage condition (since Startup Transformer No. 2 is not sufficient to simultaneously provide power for full loading from both units.)

With an Engineered Safeguards Actuation System (ESAS) signal present, certain required unit loads are placed in service in a predetermined sequence. Within 1 minute after the initiating signal is received by the load sequencing timers, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are in service.

BACKGROUND (continued)

The onsite standby power source for each 4.16 kV ES bus is a dedicated DG. DGs 1 and 2 are dedicated to ES buses A3 and A4, respectively. A DG starts automatically on an applicable Engineered Safeguards Actuation System (ESAS) signal or on an ES bus degraded voltage or undervoltage signal (see LCO 3.3.5, "Engineered Safeguards Actuation System (ESAS) Instrumentation" and LCO 3.3.8, "Diesel Generator (DG) Loss of Power Start (LOPS)"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ES bus undervoltage or degraded voltage, independent of or coincident with an ESAS signal. The DGs will also start and operate in the standby mode without tying to the ES bus on an ESAS signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ES bus. When the DG is tied to the ES bus, loads are then sequentially connected to their respective ES bus by the automatic load sequencing timers. The sequencing timers control the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

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

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received by the load sequencing timers, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for emergency DGs 1 and 2 satisfy the guidance of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 2600 kW with 10% overload permissible for up to 2 hours in any 24 hour period. However, the “intended service” rating provided by the manufacturer is 2750 kW. This is the value used in postulated DG loading evaluations (Ref. 2). The ES loads that are powered from the 4.16 kV ES buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the SAR, Chapter 14 (Ref. 4), assume ES 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 ES systems so that the fuel, Reactor Coolant System (RCS), and reactor building 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, “Reactor Building Systems.”

APPLICABLE SAFETY ANALYSES (continued)

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 that consider:

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

b. A worst-case single failure.

In MODES 1 and 2, the AC sources satisfy Criterion 3 of 10 CFR 50.36 (Ref. 5). In MODES 3 and 4, the AC sources satisfy Criterion 4 of 10 CFR 50.36.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and separate and independent DGs for each ES train (emergency DGs 1 and 2) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormality or a postulated DBA.

Qualified offsite circuits are those that are described in the SAR and are part of the licensing basis for the unit.

Each required offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ES buses.

The power sources for the two required offsite power circuits shall consist of:

a. Startup Transformer No. 1 and its 22 kV supply from the switchyard bus tie autotransformer, or the Unit Auxiliary Transformer and its supply from the switchyard bus tie autotransformer via the 22 kV overhead swing leads (alternate configuration of the Unit Auxiliary Transformer), and

b. Startup Transformer No. 2 and its supply from the 161 kV switchyard ring bus.

An offsite circuit includes the necessary breakers and equipment to properly align the circuit and transmit power from the transmission line source to a single 4160 V ES bus. The offsite power sources shall be capable of supplying 4160 V ES bus A3 via 4160 V bus A1 and 4160 V ES bus A4 via 4160 V bus A2. Either offsite source may be used to supply either ES bus. In this manner, along with the emergency DGs, each 4160 V ES bus is assured at least one offsite and one DG source of power. The inability of one offsite power source to supply one 4160 V ES bus does not render the offsite source inoperable as long as it remains capable of supplying the other 4160 V ES bus. However, when power to the ES bus is being

LCO (continued)

supplied from the main generator via the Unit Auxiliary Transformer, automatic transfer capability to either Startup Transformer No. 1 or No. 2 is required to consider the offsite power source operable to the associated ES bus.

LCO 3.8.9 addresses the OPERABILITY of vital AC distribution systems, including 4160 V ES buses A3 and A4. From this respect, if power from an offsite source is verified available to the vital 4160 V ES buses (actively supplying power to the bus or appropriate switchgear and electrical components available to allow connection to the bus), then the offsite source is considered operable. Failures associated with A3 or A4, such as a loss of bus undervolatge protection, affect only bus operability and do not require the offsite power source to be considered inoperable. However, if bus A1 or A2 is not capable of supplying bus A3 or A4, respectively, one of the offsite circuits must be considered inoperable.

One required offsite source shall be capable of accepting emergency loads in an automatic transfer. Reference 1 requires one circuit to be available within a few seconds following a LOCA to assure that core cooling, reactor building integrity, and other vital safety functions are maintained. The other required offsite source may be configured for manual transfer. In the event Startup Transformer No. 2 is configured for automatic transfer, the selective load-shed features for automatic shedding of loads to avoid a degraded voltage condition shall be OPERABLE.

For the offsite AC sources, independence is maintained to the extent practical. An offsite source may be connected to more than one ES bus and not violate the independence criteria provided each OPERABLE required offsite source is capable of being aligned (manually or automatically, as appropriate) so that it is independent of the other required offsite source.

When the main generator is synchronized to the 500 kV system, AC power for the ES loads may be supplied from either the Unit Auxiliary Transformer, Startup Transformer No. 1, Startup Transformer No. 2, or a combination of these transformers concurrently sharing the load. Power from the Unit Auxiliary Transformer, when powered from the main generator, is not credited with meeting the requirements of LCO 3.8.1.a since it cannot function under all conditions (i.e., following a turbine trip) except when connected in the alternate configuration described above. However, powering the ES buses from the Unit Auxiliary Transformer is permitted during normal unit operation because of the automatic transfer capability to a startup transformer source.

Each DG (DG1 and DG2) must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ES bus on detection of bus undervoltage. This will be accomplished within 15 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ES buses.

LCO (continued)

Proper sequencing of loads, including tripping of non-essential loads, is a required function for DG OPERABILITY. Should the time intervals between two or more loads be reduced such that the interval is less than that assumed in the SAR, the associated diesel generator is considered to be inoperable. If one or more time delays is inoperable (i.e., the associated component fails to load) then the associated component is considered inoperable, and the appropriate Condition for that component is entered.

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 DGs, separation and independence are complete.

This LCO does not apply to the Alternate AC DG nor to the security DG.

APPLICABILITY

The AC sources 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 abnormalities or abnormal transients; and

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

The AC power requirements for MODES 5 and 6 are addressed by the definition of OPERABILITY for each required supported load.

ACTIONS

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 being 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.

The Completion Time provides for a prompt confirmation of the OPERABILITY of the remaining offsite circuit. This is considered to be acceptable because of other indications, which are available in the control room for loss of the remaining offsite circuit.

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 DG 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 available to supply its loads; and

b. A 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 required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to both trains 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

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, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

ACTIONS (continued)

A.3 (continued)

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.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 17 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between the 72 hour and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

Required Action A.3 has been modified by a Note extending the allowable outage time for Startup Transformer No. 2 only, for up to 30 days. The 30-day allowance is permitted not more than once in any 10-year period, which is considered sufficient for proper maintenance of the transformer. The 30-day window should permit extensive preplanned preventative maintenance without placing either unit in an action statement of short duration and would allow both units to be operating during such maintenance. Because this allowance assumes parts are prestaged, appropriate personnel are available, and proper contingencies have been established, it is not intended to be used for an unexpected loss of the transformer. Pre-established contingencies will consider the projected stability of the offsite electrical grid, the atmospheric stability projected for the maintenance window, the ability to adequately control other ongoing plant maintenance activities that coincide with the window, projected flood levels, and the availability of all other power sources. Since a station blackout is the most affected event that could occur when power sources are inoperable, the steam driven emergency feedwater pump will also be maintained available during the evolution.

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with an inoperable DG, 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 a 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.

The Completion Time provides for a prompt confirmation of the OPERABILITY of the remaining offsite circuit. This is considered to be acceptable because of other indications, which are available in the control room for monitoring the status of the remaining offsite circuit.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

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 DG exists; and

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

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

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

ACTIONS (continued)

B.2 (continued)

In this Condition, the remaining OPERABLE DG 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 DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG 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 DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the condition reporting 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. 6), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

Operation may continue in Condition B for a period that should not exceed 7 days. In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution 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 second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not

ACTIONS (continued)

B.4 (continued)

met for up to 72 hours. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Condition A and Condition B are entered concurrently. The "AND" connector between the 7 day and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

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 safety functions. 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 a Completion Time of 24 hours is allowed 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. These features are powered from redundant AC safety trains.

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 required feature is inoperable.

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

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 DGs 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.

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 System ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train (one or more trains), 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 DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. 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.

ACTIONS (continued)

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ES 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.

With both DGs 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 12 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.

G.1

Condition G 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 SAR, Section 1.4, GDC 18 (Ref. 7). Periodic component tests are supplemented by extensive functional tests during outages (under simulated accident conditions).

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify “ready-to-load” a minimum output voltage of 3750 V (~90% of the nominal 4160 V output voltage) is applicable. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The required minimum frequency for loading of the DG is 58.8 Hz (derived from Safety Guide 9); however, this value is not routinely monitored to be within limit within 15 seconds. Meeting minimum frequency is expected prior to the DG voltage reaching the required minimum. This is administratively confirmed on an 18 month interval.

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

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, this SR is modified by a Note to indicate that DG starts for this Surveillance 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 testing with application of the Note, the DGs are started from standby conditions. Standby conditions for a DG means that the diesel engine oil is being continuously circulated and temperature is being maintained consistent with manufacturer recommendations. The signal initiating the start of the DG is varied from one test to another (start with handswitch at control room panel and at DG local control panel) to verify all starting circuits are OPERABLE.

SR 3.8.1.2 requires that the DG starts from standby conditions and achieves “ready-to-load” conditions (i.e., minimum voltage) within 15 seconds. The 15 second start requirement supports the assumptions of the design basis LOCA analysis in the SAR, Chapter 14 (Ref. 4).

The 31 day Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting full rated load. The load test is conducted at 90 to 100 percent of the continuous rating, which is considered to be 90 to 100 percent of the intended service rating, or ≥ 2475 kW and ≤ 2750 kW. These parameter values contain all necessary allowances for instrument uncertainty. No additional allowances for instrument uncertainty are required to be incorporated in the implementing procedures. A minimum run time of 60 minutes ensures stabilized engine temperatures, while minimizing the time that the DG is connected to the offsite source.

The 31 day Frequency for this Surveillance provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

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 (e.g., because of changing bus loads) do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the engine mounted day tank is being properly maintained. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel , when combined with the volume contained in one fuel oil storage tank, for not less than 3.5 days operation of one DG loaded to full capacity (Ref. 2).

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.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day [and engine mounted] 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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5 (continued)

during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 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

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support 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, and the fuel delivery piping is not obstructed.

The design of the fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during DG monthly testing. Therefore, a 31 day Frequency is specified to correspond to the interval for DG testing.

SR 3.8.1.7

Transfer of each 4.16 kV ES bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. Reference 1 requires that only one of the two offsite power circuits be capable of automatic transfer. The second (alternate) circuit must be capable of manual transfer, as a minimum. Typically, Startup Transformer No. 1 is aligned for automatic transfer and Startup Transformer No. 2 is aligned to allow manual transfer. In this alignment, the Surveillance verifies the automatic transfer of loads to Startup Transformer No. 1 and the manual transfer of loads to Startup Transformer No. 2. In the event that Startup Transformer No. 2 is aligned for automatic transfer and Startup Transformer No. 1 is aligned for manual transfer, the Surveillance verifies the automatic transfer of loads to Startup Transformer No. 2 and the manual transfer of loads to Startup Transformer No. 1.

For Startup Transformer No. 2, this test also demonstrates the selective load shedding interlock function. (Note: This load shedding function is only required when Startup Transformer No. 2 is selected for automatic transfer.) These features provide protection of required equipment from a sustained degraded grid voltage situation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7 (continued)

The 18 month Frequency of the Surveillance takes into consideration the unit conditions required to perform the Surveillance (i.e., during refueling shutdown), and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note 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 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 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 MODES 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.8

This Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the non-essential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve “ready-to-load” conditions (i.e., minimum required voltage) within the specified time.

The DG auto-start time of 15 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, e.g., the running service water pump(s), is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads can not actually be connected or loaded

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8 (continued)

without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads during this test, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

If the component start time delays are outside of those assumed by the SAR, component OPERABILITY and DG OPERABILITY must be evaluated.

The Frequency of 18 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 a Note. The reason for the Note is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

SR 3.8.1.9

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

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.7, during a loss of offsite power actuation test signal in conjunction with an ES actuation signal. This test is typically conducted by simulating an ESAS signal and either simultaneously or subsequently simulating a LOOP. In certain circumstances, many loads can not actually be connected or loaded without undue hardship or potential for undesired operation. For instance, DHR systems performing a DHR function are not desired to be interrupted from this mode of operation. In lieu of actual demonstration of connection and loading of loads during this test, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

For ANO-1, the High Pressure Injection (HPI) pump load is excluded from this DG test; although its auto start logic and load sequencing time are included in the test. HPI pump start under accident flow conditions can challenge LTOP protection considerations when the RCS is closed and challenge pump integrity due to excessive flow or inadequate suction when the RCS is open. The remaining loads that are auto-connected during this test in conjunction with design calculations are sufficient to demonstrate that the DG will perform as designed during a LOCA with coincident LOOP event.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

Should the time intervals between two or more loads be reduced such that the interval is less than that assumed in the SAR, the associated DG is conservatively considered to be inoperable unless an evaluation of the condition shows the loading of the DG, with the reduced time interval, to be acceptable. If one or more time delays is inoperable (i.e., the associated component fails to load) or the time interval between two or more loads is greater than assumed in the SAR, then the associated component is considered inoperable, and the appropriate Condition for that component is entered.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by a Note. The reason for the Note is to minimize wear and tear on the DGs during testing. For the purpose of this testing with application of the Note, the DGs are started from standby conditions, that is, with the engine oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs.

REFERENCES

1. SAR, Section 1.4, GDC 17.

2. SAR, Chapter 8.

3. Regulatory Guide 1.9, “Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants,” Rev. 3, July 1993.

4. SAR, Section 1.4, GDC 18.

5. SAR, Chapter 14.

6. 10 CFR 50.36.

7. Generic Letter 84-15, “Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability,” July 2, 1984 (0CNA078423).

8. Regulatory Guide 1.137, Rev. 1, October 1979.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND

The unit shutdown Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternates) and the onsite standby power sources (emergency diesel generators (DGs) and the Alternate AC (AAC) DG).

Offsite power is supplied to the unit switchyard from the transmission network by five transmission lines. From the switchyard, two electrically and physically separated offsite circuits provide AC power, through either the startup transformers or the unit auxiliary transformer, to the 4.16 kV ES buses. ES buses A3 and A4 may be cross-tied during operation in shutdown conditions. A description of the offsite power network and the circuits to the Class 1E ES buses is found in the SAR, Chapter 8 (Ref. 1).

When the unit is off-line, unit equipment is typically powered from a startup transformer or from the unit auxiliary transformer back fed from the 500 kV switchyard. If the power source is transferred to startup transformer No. 2, sufficient loads are automatically shed or procedurally limited to avoid a degraded voltage condition (since startup transformer No. 2 is not sufficient to simultaneously provide power for full loading from both units.)

The normal onsite standby power source for each 4.16 kV ES bus is a dedicated DG. DGs 1 and 2 are dedicated to ES buses A3 and A4, respectively. ES buses A3 and A4 may be cross-tied during operation in shutdown conditions. Ratings for emergency DGs 1 and 2 satisfy the guidance of Regulatory Guide 1.9 (Ref. 2). The continuous service rating of each DG is 2600 kW with 10% overload permissible for up to 2 hours in any 24 hour period. However, the “intended service” rating provided by the manufacturer is 2750 kW. This is the value used in postulated DG loading evaluations (Ref. 3).

The AAC DG is an additional onsite power source. The AAC DG was installed to meet the requirements of 10 CFR 50.63(c)(iii)(2) (Ref. 4). The AAC DG and its associated power supply system is designed to provide vital and non-vital 4160 V power to either ANO-1, ANO-2, or both units simultaneously. The design considerations for the AAC DG assumed the engine would be started from the control room and be at rated speed and voltage within 10 minutes after the onset of a station blackout condition. The AAC DG has a continuous rating of 4400 kW at 4160 V. The machines prime rating, which equates to a 2 hour rating is 4840 kW (110% of the continuous rating) (Ref. 5).

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 MODES 5 or 6 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 a postulated 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 and 2 have no specific analyses in MODES 3, 4, 5, and 6. Worst-case bounding events are deemed not credible in MODES 3, 4, 5 and 6 because the energy contained within the reactor coolant 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 and 2, 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 planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO 3.8.1 requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited;

b. Requiring appropriate compensatory measures for certain conditions which may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both;

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems;

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event; and

APPLICABLE SAFETY ANALYSES (continued)

e. The unit, while in a shutdown condition, can not affect the power grid in a manner that would result in a loss of offsite power due to a turbine trip.

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 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, ANO, through industry commitment, 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.

In MODES 5 and 6, the AC sources satisfy Criterion 4 of 10 CFR 50.36 (Ref. 6). During handling of irradiated fuel, the AC sources satisfy Criterion 3 of 10 CFR 50.36.

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 DG, 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 DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of a postulated fuel handling accident.

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safeguards (ES) bus(es). Qualified offsite circuits are those that are described in the SAR and are part of the licensing basis for the unit.

One offsite circuit consists of startup transformer No. 1, its supply from the switchyard bus tie autotransformer, either the 4160 V bus A1 or A2, and the feeder breaker providing power to the required 4160 V ES bus(es). An alternative for this offsite circuit consists of the unit auxiliary transformer, its supply from the switchyard bus tie autotransformer and the overhead swing leads, either the 4160 V bus A1 or A2, and the feeder breaker providing power to the required 4160 V ES bus(es). A second offsite circuit consists of startup transformer No. 2, its supply from the

LCO (continued)

161 kV switchyard ring bus, either the 4160 V bus A1 or A2, and the feeder breaker providing power to the required 4160 V ES bus(es). Another alternative for the above described offsite circuits consists of the unit auxiliary transformer, its supply from the 500 kV switchyard via backfeed through the main transformer (with the main generator disconnects removed), either the 4160 V bus A1 or A2, and the feeder breaker providing power to the required 4160 V ES bus(es). An offsite circuit includes the necessary breakers and equipment to properly align the circuit from the transmission line sources to the required 4160 V ES bus(es). Only one of the possible offsite circuits is "required" provided it can supply the required Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10. If a single offsite circuit cannot provide all the required distribution subsystem(s), a second offsite circuit is also "required."

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply the required equipment.

The DG (DG 1, DG 2, or AAC DG) must be capable of being started, accelerating to rated speed and voltage, and being connected to its respective ES bus on determination of a loss of offsite power. The DG must be capable of accepting all required loads, and must continue to operate until offsite power can be restored to the ES buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby at ambient conditions.

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single onsite power source to supply the required equipment.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies in either the reactor building or fuel handling area provide assurance that:

a. Systems to provide adequate decay heat removal are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident involving handling irradiated fuel 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 MODE 5 or 6.

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 would not specify an 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

An offsite circuit would be considered inoperable if it were not available to one required ES train. Although two trains may be 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 CORE ALTERATIONS and 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, A.2.4, B.1, B.2, B.3, and B.4

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 DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in both the reactor building and the fuel handling area, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). 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 which 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 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 a fuel handling accident. 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.

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

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.

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 ES 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 3.8.1.4 is not required to be met since crediting manual start of the required DG provides sufficiently opportunity to ensure that the fuel oil transfer system is operating properly. SR 3.8.1.7 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.8 and SR 3.8.1.9 are not required to be met because they provide for testing of engineered safeguards actuation signals which are not required to be OPERABLE except in MODES 1, 2, 3, and 4. Automatic actuation and loading of the DGs is not assumed in MODES 5 and 6.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V ES bus or disconnecting a required offsite circuit during performance of this SR. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that this SR must be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE. When Note 1 is considered, SR 3.8.2.1 requires the following:

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.2.1 (continued)

SR 3.8.1.1 must be performed and met,
SR 3.8.1.2 must be performed and met,
SR 3.8.1.3 must be met, but does not have to be performed,
SR 3.8.1.4 does not have to be performed or met,
SR 3.8.1.5 must be performed and met,
SR 3.8.1.6 must be performed and met,
SR 3.8.1.7 does not have to be performed or met,
SR 3.8.1.8 does not have to be performed or met, and
SR 3.8.1.9 does not have to be performed or met.

Note 2 exempts the 15 second start acceptance criteria for SR 3.8.1.2. This allows the AAC DG power source, which does not have auto-start capability or start-time criteria, to be used in lieu of an emergency DG. In MODES 5 and 6, there is sufficient time to manually start a DG in the event the offsite power source is lost. The required DG must be capable of being started from standby conditions and achieving ready-to-load conditions. Although the time to reach ready-to-load conditions is not a part of the acceptance criteria, it is intended that for emergency DG tests, this time be trended to help determine if a condition exists that is degrading the starting capabilities of the DG.

Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

1. SAR, Chapter 8.

2. Regulatory Guide 1.9, "Selection, Design, and Qualification of Diesel Generator Units used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants," Rev. 3, July 1993.

3. Calculation 86-E-0002-01.

4. 10 CFR 50.63(c)(iii)(2).

5. ANO-2 SAR Section 8.3.3.

6. 10 CFR 50.36.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with fuel oil storage capacity sufficient to operate that diesel for a period of 3.5 days while the DG is supplying maximum post loss of coolant accident load demand discussed in the SAR, Section 8.3 (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are initially available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time needed to replenish the onsite supply from outside sources.

Fuel oil is transferred from either storage tank to either day tank by either transfer pump (one pump is associated with each storage tank). Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG. All required outside tanks, pumps, and piping are located underground.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices. 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. See Specification 5.5.13, “Diesel Fuel Oil Testing Program,” for details.

Each DG has a designed air start system consisting of two redundant banks of two tanks (receivers) each. One bank of the two tanks contains adequate capacity (i.e., design margin) for five successive start attempts on the DG without recharging the air start receivers.

APPLICABLE SAFETY ANALYSES

The applicable Design Basis Accident (DBA) and transient analyses for the Diesel Fuel Oil and Starting Air systems are the same as for the DGs which they support. See the appropriate discussions in the Bases for LCO 3.8.1, “AC Sources – Operating” and LCO 3.8.2, "AC Sources – Shutdown."

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3).

LCO

Stored diesel fuel oil is required to have sufficient supply for 3.5 days of full load operation. It is also required to meet specific standards for quality. This requirement supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an abnormality or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1 and 3.8.2.

The starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormality or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the required fuel oil supply for a DG of 20,000 gallons (i.e., 138 inches) is not available. However, the Condition is restricted to fuel oil level reductions, that maintain at least a 3 day supply of 17,140 gallons (i.e., 118 inches). These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level. 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 DG inoperable. This period is acceptable based on the remaining capacity (> 3 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

ACTIONS (continued)

B.1

This Condition is entered as a result of a failure to meet the acceptance criterion of Specification 5.5.13. 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 DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

C.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.2 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 a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

D.1

With starting air receiver pressure < 175 psig in the required receivers, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 158 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that the credited DG start is accomplished on the first attempt, and the low probability of an event during this brief period.

E.1

With a Required Action and associated Completion Time not met, or one or more DGs with fuel oil or required starting air subsystem not within limits for reasons other than addressed by Conditions A through D, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks, when combined with the volume contained in the DG fuel oil day tanks, to support each DG's operation for 3.5 days at full load. The 3.5 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location. An indicated tank level of 138 inches of fuel oil assures the required volume of 20,000 gallons for tanks T-57A and T-57B.

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

The tests of fuel oil prior to addition to the storage tanks 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 operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between sampling (and associated results) of new fuel and addition of new fuel oil to the storage tank(s) to exceed 31 days. The tests, limits, and applicable ASTM Standards for the tests listed in Specification 5.5.13, “Diesel Fuel Oil Testing Program,” are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-88 (Ref. 4); and

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 4) that the sample has:

    1. an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27°, ≤ 39°,

    2. a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes,

    3. a flash point of ≥ 125°F, and

    4. water and sediment within limits.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2 (continued)

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 4) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 4), except that the analysis for sulfur may be performed in accordance with ASTM D1552-90 (Ref. 4) or ASTM D2622-87 (Ref. 4). These additional analyses are required by Specification 5.5.13, "Diesel Fuel Oil Testing Program," to be performed within 31 days following sampling and addition. This 31 days is intended to assure: 1) that the sample taken is not more than 31 days old at the time of adding the fuel oil to the storage tank, and 2) that the results of a new fuel oil sample (sample obtained prior to addition but not more than 31 days prior to) are obtained within 31 days after addition. For circumstances where multiple fuel oil additions are made within a short period of time, the samples taken for each batch added to the storage tank can be composited for a single follow-up analysis. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, 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, Method A (Ref. 4). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each tank is considered and tested separately.

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 3.8.3.3

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4

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 DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

REFERENCES

1. SAR, Section 8.3.

2. Regulatory Guide 1.137.

3. 10 CFR 50 36.

4. ASTM Standards: D4057-88; D975-81; D4176-86; D1552-90; D2622-87; D2276-88, Method A.

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 120 VAC vital bus power (via inverters). As required by SAR, Section 1.4, 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 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Red Train and Green Train). Each subsystem consists of one 125 VDC battery, the associated battery charger for each battery, and all the associated control equipment and interconnecting cabling.

Additionally, there is one spare battery charger per subsystem, which provides backup service in the event that a battery charger is out of service. If the spare battery charger is substituted, then the requirements of independence and redundancy between subsystems are maintained.

During normal operation, each 125 VDC subsystem is powered from the inservice battery charger with the battery floating on the system. In case of a loss of normal power to the battery charger, the DC load is automatically powered from the station battery. This results in a discharge of the associated battery (and may affect both the system and cell parameters).

The Red Train and Green Train DC electrical power subsystems 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 subsystems also provide DC electrical power to the inverters, which in turn power the 120 VAC vital buses.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distributions System – Operating."

Each battery has adequate storage capacity to carry the required load continuously for at least 2 hours in addition to supplying power for the operation of momentary loads during the 2 hour period as discussed in the SAR, Chapter 8 (Ref. 4).

BACKGROUND (continued)

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

The batteries for Red Train and Green Train DC electrical power subsystems 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 Red Train and Green Train batteries are C&D type LCR-21 (58 cell). This size of battery was required before the black battery was added because of the large non-1E lift oil and seal oil pump motors fed from the 1E batteries. The LCR-21 batteries have 10 positive plates and with the present loads the calculated positive plate requirement for the Red Train battery is 6 and for the Green Train battery is 5 (this includes temperature correction for 60º F and 1.25 for end-of-life). This provides an approximate 65% design margin for Red Train battery and an approximate 100% design margin for the Green Train battery. IEEE 485 (Ref. 5) recommends a 10-15% design margin. IEEE 485 is used as a reference in the battery sizing calculation which is the document, along with the battery test procedure, used to determine that the batteries are adequately sized.

Each subsystem 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 is also designed with sufficient capacity to restore the battery from the design minimum charge to its fully charged state while supplying normal steady state loads.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the SAR, Chapter 14 (Ref. 6), assume that Engineered Safeguards (ES) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions that consider:

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

b. A worst-case single failure.

In MODES 1 and 2, the DC sources satisfy Criterion 3 of 10 CFR 50.36 (Ref. 7). In MODES 3 and 4, the DC sources satisfy Criterion 4 of 10 CFR 50.36.

LCO

The DC electrical power subsystems, each subsystem consisting of one battery, one of two battery chargers 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 abnormality or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power subsystem requires the associated battery to be OPERABLE and connected to the associated DC bus and one of its respective chargers to be operating and connected to the associated DC bus.

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 abnormalities; and

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

The DC electrical power requirements for MODES 5 and 6 are addressed by the definition of OPERABILITY for each required supported load.

ACTIONS

A.1

Condition A 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 8 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery chargers, or inoperable battery chargers and associated inoperable battery), 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 would, however, result in the complete loss of the remaining 125 VDC electrical power subsystems with attendant

ACTIONS (continued)

A.1 (continued)

loss of ES functions, continued power operation should not exceed 8 hours. The 8 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1 and B.2

If the inoperable DC electrical power subsystem 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 12 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery (2.15 V per cell average) and are consistent with IEEE-450 (Ref. 8). The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

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.

The Surveillance Frequency of 18 months is consistent with considerations that the battery service test should be performed during refueling outages, or at some other outage.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2 (continued)

A modified performance discharge test may be performed in lieu of a service test.

The modified performance discharge test (Ref. 8) is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, 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 rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified performance discharge test is a test of the battery capacity, as found, 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 and the test discharge rate must envelope the duty cycle of the service test if the modified performance discharge test is performed in lieu of a service test.

SR 3.8.4.3

A battery performance discharge test is a test of constant current capacity of a battery 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 (Ref. 8).

A battery modified performance discharge test is described in the Bases for SR 3.8.4.2. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.3; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.3 while satisfying the requirements of SR 3.8.4.2 at the same time.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 8), which recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3 (continued)

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. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is > 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

REFERENCES

1. SAR, Section 1.4, GDC 17.

2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," March, 1971.

3. IEEE-308-1971, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

4. SAR, Chapter 8.

5. IEEE-485-1993, June 1983.

6. SAR, Chapter 14.

7. 10 CFR 50.36.

8. IEEE-450-1995, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

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 DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the fuel handling accident and the requirements for the supported systems' OPERABILITY.

In general, when the unit is shutdown, 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 and 2 have no specific analyses in MODES 3, 4, 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.

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 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, ANO, through industry commitment, 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.

BACKGROUND (continued)

In MODES 5 and 6, the DC sources satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1). During handling of irradiated fuel, the DC sources satisfy Criterion 3 of 10 CFR 50.36.

LCO

The DC electrical power subsystems consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support the required train(s) 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 a fuel handling accident.

An OPERABLE DC electrical power subsystem requires the associated battery to be OPERABLE and connected to the associated DC bus and one of its respective chargers to be OPERABLE and capable of being connected to the associated DC bus.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies in either the reactor building or fuel handling area, provide assurance that:

a. Required features to provide adequate decay heat removal are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident in either the reactor building or fuel handling area 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 MODE 5 or 6.

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 would not specify an 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.1.1, A.1.2, A.1.3, A.1.4, and A.1.5

With the required DC electrical subsystem inoperable (e.g., inoperable battery, no OPERABLE battery charger, or both) there may be insufficient capability to mitigate the consequences of a fuel handling accident. Therefore, conservative actions must be taken (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in both the reactor building and the fuel handling area, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). 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 which 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 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 a fuel handling accident. It is further required to immediately initiate action to restore the required DC electrical power subsystem and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required low temperature overpressure protection (LTOP) System feature may be inoperable. In this case, Required Actions A.1.1 through A.1.4 do not adequately address the concerns relating to LTOP. Pursuant to LCO 3.0.6, the LTOP ACTIONS would not be entered. Therefore, Required Action A.1.5 is provided to direct entry into the appropriate LTOP Conditions and Required Actions, which results in taking the appropriate LTOP actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystem should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires the DC Sources to be capable of meeting the requirements of SR 3.8.4.1 through SR 3.8.4.3.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC source from being discharged below its 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 during periods when the DC Source is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.4 for discussion of each SR.

When the Note is considered, SR 3.8.5.1 requires the following for an OPERABLE DC Source:

SR 3.8.4.1 must be performed and met,
SR 3.8.4.2 must be met, but does not have to be performed, and
SR 3.8.4.3 must be met, but does not have to be performed.

As an example, typical operation during a refueling shutdown (in MODES 5 and 6) requires only one OPERABLE battery. However, the SRs with an 18 month Frequency which are not required to be performed on the OPERABLE battery should be conducted on each battery during that portion of the refueling shutdown that it is not required to be OPERABLE so that the SRs are current when it is time to enter MODES 1, 2, 3, and 4. This is to allow continued OPERABILITY of the battery during MODES 5 and 6 even if the Frequency for SR 3.8.4.2 or SR 3.8.4.3 is not met.

REFERENCES

1. 10 CFR 50.36

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources – Operating," and LCO 3.8.5, "DC Sources – Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the SAR, Chapter 14 (Ref. 1), assume Engineered Safeguards systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions that consider:

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

b. A worst-case single failure.

Battery cell parameters satisfy Criterion 3 of 10 CFR 50.36 (Ref. 2).

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an abnormality or a postulated DBA. The limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery cell parameters are only required to be within limits when the DC power source is required to be OPERABLE. See the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

The Actions Table is modified by a Note, which indicates that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DC subsystem. Complying with the Required Actions for one inoperable DC subsystem may allow for continued operation, and subsequent inoperable DC subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

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

With one or more cells in one or more batteries not within limits (i.e., Category A limits not met or Category B limits not met or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1 in the accompanying LCO, the battery is degraded but there still is sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). These checks will provide a quick representative indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to within the Category A and B limits, the battery will still be capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because parameter measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to within Category A and B limits. This periodic verification is consistent with the increased potential to exceed these battery cell parameter limits during these conditions.

ACTIONS (continued)

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable prior to declaring the battery inoperable.

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement may not be available. Therefore, the battery must be immediately declared inoperable and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as the Required Actions and associated Completion Time of Condition A not met or average electrolyte temperature of representative cell falling below 60°F, are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte level and temperature of pilot cells.

SR 3.8.6.2 and SR 3.8.6.4

This Surveillance verification that the average temperature of representative cells is ≥ 60°F is consistent with a recommendation of IEEE-450 (Ref. 3), which states that the temperature of electrolytes in the pilot cell should be determined at least once per month and that the temperature in representative cells (~10% of all connected cells) should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). In addition, within 24 hours of a battery discharge < 110 V or a battery overcharge > 145 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V, do not constitute a battery discharge provided battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra 1/4 inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote (a) to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on a recommendation of IEEE-450 (Ref. 3), which states that prolonged operation of cells < 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195 (0.020 below the manufacturer fully charged nominal specific gravity). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3 (continued)

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.190 (0.025 below the manufacturer fully charged, nominal specific gravity) with the average of all connected cells > 1.195 (0.020 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists and the battery must be declared inoperable.

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limits for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limits of average specific gravity ≥ 1.190 is based on manufacturer recommendations (0.025 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

Footnotes (b) and (c) to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above mentioned correction for electrolyte temperature.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. SAR, Chapter 14.

2. 10 CFR 50.36.

3. IEEE-450-1995, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

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 buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the bus. The inverters are normally powered from the 125 VDC Electrical Power System. The inverters provide an uninterruptible power source for the safety significant instrumentation and controls, including the Reactor Protection System (RPS), the Engineered Safeguards Actuation System (ESAS), and the Emergency Feedwater Initiation and Control (EFIC) system. There are two RPS/ESAS related inverters per train and an additional green train safety related inverter Y28 that supports some post accident monitoring instrumentation, decay heat removal system interlocks, and control circuitry for systems such as emergency feedwater (EFW) and pressurizer pressure control. Additionally, there are two swing inverters (one per train) which provide backup service in the event that an RPS/ESAS related inverter is out of service. If the swing inverter is placed in service, requirements of independence and redundancy between trains are maintained. Specific details on inverters and their operating characteristics are found in SAR, Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the SAR, Chapter 14 (Ref. 2), assume Engineered Safeguards 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 safety significant instrumentation and controls so that the fuel, Reactor Coolant System, and reactor building 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, “Reactor Building 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 AC vital buses OPERABLE during accident conditions that consider:

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

b. A worst-case single failure.

APPLICABLE SAFETY ANALYSES (continued)

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36 (Ref. 3) in MODES 1 and 2. In MODES 3 and 4, the inverters satisfy Criterion 4 of 10 CFR 50.36.

LCO

The inverters ensure the availability of AC electrical power for the instrumentation required to shut down the reactor and maintain it in a safe condition after an abnormality or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the safety significant instrumentation and controls is maintained. The four RPS/ESAS related inverters (two per train) along with inverter Y28 ensure an uninterruptible supply of AC electrical power to the 120 VAC buses even if the 4.16 kV safety buses are de-energized.

OPERABLE inverters require the associated 120 VAC vital bus to be powered by the inverter with output voltage within tolerances, and power input to the inverter from a 125 VDC Electrical Power System with associated OPERABLE station battery.

This LCO is modified by a Note that allows one of the four RPS/ESAS related inverters to be disconnected from its associated DC bus for ≤ 2 hours to allow load transfer to or from a swing inverter, if the 120 VAC bus is powered from an alternate AC source during the period and the other three inverters are OPERABLE.

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 abnormalities; and

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

Inverter requirements for MODES 5 and 6 are addressed by the definition of OPERABILITY for each required supported load.

ACTIONS

A.1

With one of the four inverters required by LCO 3.8.7.a and LCO 3.8.7.b inoperable, the associated 120 VAC bus is automatically transferred to its alternate AC source and remains OPERABLE. In the event the automatic transfer fails and the associated 120 VAC bus is de-energized, the 120 VAC bus is considered to be inoperable. For this reason, a Note has been included in ACTION A requiring entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures the bus is re-energized within 8 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24-hour limit takes into consideration the time required to repair an inverter, the availability of a swing inverter, and the additional risk to which the unit is exposed because of the inverter inoperability. This must 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 bus is powered from its alternate AC source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120 VAC buses is the preferred source for powering instrumentation trip setpoint devices.

B.1

With inverter Y28 inoperable, the associated 120 VAC bus C540 is automatically transferred to its alternate AC source and remains OPERABLE. In the event the automatic transfer fails and the associated 120 VAC bus is de-energized, the 120 VAC bus is considered to be inoperable. For this reason, a Note has been included in ACTION B requiring entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating."

Required Action B.1 allows 72 hours to fix the inoperable inverter and return it to service. The 72-hour limit takes into consideration the time required to repair an inverter, the fact that Y28/C540 does not have a swing inverter, and the additional risk to which the unit is exposed because of the inverter inoperability. This must 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 bus is powered from its alternate AC source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120 VAC bus is the preferred source for powering instrumentation and controls.

ACTIONS (continued)

C.1

Because Y28 is powered from the green train, a loss of Y28 in conjunction with an inoperable red train inverter required by LCO 3.8.7.a may result in a loss of safety function if power is lost to their respective 120 VAC buses. Therefore, one of these inoperable inverters must be restored to OPERABLE status within 2 hours. The 2-hour restoration period is acceptable since it is unlikely that both Y28 and the inoperable red train inverter will fail to continue to supply their respective 120 VAC buses with power from the alternate AC source. In the unlikely event that both affected 120 VAC buses are de-energized, LCO 3.8.9 Required Action E.1 will require immediate entry into LCO 3.0.3 due to the likelihood that a loss of safety function has occurred.

D.1 and D.2

If the Required Actions and associated Completion Time are not met or if any two inverters required by LCO 3.8.7.a and LCO 3.8.7.b are inoperable, 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 12 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 buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the 120 VAC 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. SAR, Chapter 8.

2. SAR, Chapter 14.

3. 10 CFR 50.36.

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 DC to AC inverters are designed to provide the required capacity, capability, and reliability to ensure the availability of necessary power to safety significant instrumentation and controls.

The OPERABILITY of the inverters is consistent with the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the required inverters to each required 120 VAC vital bus during MODES 5 and 6 ensures that:

a. The unit can be maintained in MODE 5 or 6 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 a postulated fuel handling accident.

In general, when the unit is shutdown, 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 and 2 have no specific analyses in MODES 3, 4, 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 minimal in consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

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 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, ANO, through industry commitment, 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.

In MODES 5 and 6, the inverters are part of the distribution system and, as such, satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1). During handling of irradiated fuel, the inverters satisfy Criterion 3 of 10 CFR 50.36.

LCO

The inverters provide an uninterruptible supply of AC electrical power to its 120 VAC vital bus even if the 4.16 kV safety buses are de-energized. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of a postulated fuel handling accident.

An OPERABLE inverter must be supplied power from its associated Class 1E 125 VDC electrical power system, and supplying the associated AC vital bus with acceptable output AC voltage.

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies in either the reactor building or fuel handling area provide assurance that:

a. Systems to provide adequate decay heat removal 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 MODE 5 or 6.

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 would not specify an 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.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant inverters to be OPERABLE, one OPERABLE inverter may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). 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 which 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 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 a fuel handling accident. 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.

Notwithstanding performance of the above conservative Required Actions, a required low temperature overpressure protection (LTOP) system feature may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to LTOP. Pursuant to LCO 3.0.6, the LTOP ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct entry into the appropriate LTOP Conditions and Required Actions, which results in taking the appropriate LTOP actions.

ACTIONS (continued)

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 the alternate AC source.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and 120 VAC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation 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. 10 CFR 50.36.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems – Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and 120 VAC bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and 120 VAC bus electrical power distribution subsystems.

Each AC electrical power subsystem consists of an Engineered Safeguards (ES) 4.16 kV bus and 480 V buses. Each 4.16 kV ES bus has two offsite sources of power as well as a dedicated onsite diesel generator (DG) source as described in the Bases for LCO 3.8.1, “AC Sources - Operating.” If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16 kV ES bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries.

The secondary AC electrical power distribution system for each train includes the safety related load centers and motor control centers shown in Table B 3.8.9-1. Motor control center B55 is fed from motor control center B56. These motor control centers are swing components, in that motor control center B56 may be energized from either load center B5 or load center B6. Normally, motor control center B56, and thus B55, are energized from load center B6. However, this alignment may be switched to energize these motor control centers from load center B5, if needed to support the configuration of the unit.

The 120 VAC distribution panels are arranged in two load groups per subsystem and are normally powered from the inverters. Upon loss of the DC supply, or in the event of an inverter failure, a static transfer switch automatically transfers the 120 VAC vital load to an ES motor control center, and its use is governed by LCO 3.8.7, "Inverters - Operating."

There are two independent 125 VDC electrical power distribution subsystems (one for each train).

The list of all required distribution buses is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the SAR, Chapter 14 (Ref. 1), assume ES systems are OPERABLE. The AC, DC, and 120 VAC bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ES systems so that the fuel, Reactor Coolant System, and reactor building 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, “Reactor Building Systems.”

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the AC, DC, and 120 VAC 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 that consider:

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

b. A worst-case single failure.

In MODES 1 and 2, the distribution systems satisfy Criterion 3 of 10 CFR 50.36 (Ref. 2). In MODES 3 and 4, the distribution systems satisfy Criterion 4 of 10 CFR 50.36.

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and 120 VAC bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after abnormality or a postulated DBA. The AC, DC, and 120 VAC bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the AC, DC, and 120 VAC bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ES 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, load centers, and motor control centers 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 120 VAC electrical power distribution subsystems require the associated distribution panels to be energized to their proper voltage from the associated inverter via inverted DC voltage or from its alternate AC source.

In addition, cross-tie breakers between redundant safety related AC, DC, and AC bus 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 cross-tie breakers are closed, the affected redundant electrical power distribution subsystems 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 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 abnormalities; and

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

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems – Shutdown."

ACTIONS

A.1

With one or more required AC electrical power distribution subsystems inoperable, the remaining OPERABLE portions of the AC electrical power distribution subsystem(s) may be capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ES functions not being supported. Therefore, the required AC buses, load centers, and motor control centers must be restored to OPERABLE status within 8 hours.

Condition A worst case scenario is one train without AC power (i.e., no offsite power to the train and the associated DG 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.

ACTIONS (continued)

A.1 (continued)

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

B.1

With one or more 120 VAC bus electrical power distribution subsystems inoperable, the remaining OPERABLE portions of the 120 VAC bus subsystem(s) may be 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 ES functions not being supported. Therefore, the 120 VAC bus subsystem(s) must be restored to OPERABLE status within 8 hours by powering the affected bus(es) from the associated inverter via inverted DC or from its alternate AC source.

Condition B represents one or more 120 VAC bus subsystem(s) without power; potentially both the DC source and the associated alternate AC source are nonfunctioning. In this situation the unit is significantly more vulnerable to a complete loss of all un-interruptible 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 bus subsystem(s) and restoring power to the affected bus subsystem(s). The loss of any RS-panel requires entry into Condition B.

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:

ACTIONS (continued)

B.1 (continued)

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.

The 8 hour Completion Time takes into account the importance to safety of restoring the 120 VAC bus subsystem(s) to OPERABLE status, the redundant capability afforded by the other OPERABLE bus subsystem, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the 120 VAC bus subsystem(s). At this time, an AC train could again become inoperable, and 120 VAC bus subsystem(s) restored to OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With 120 VAC panel C540 inoperable, a portion of the instrumentation associated with green train equipment is lost. Because C540 is not a RPS or ESAS related panel and is limited in its effect on various system/component operabilities, it is not necessary to impose an 8-hour Completion Time for panel restoration. However, it is important to ensure that equipment affected by the loss of C540 is quickly identified and appropriate corrective actions taken. Therefore, Required Action C.1 requires entry into the appropriate Conditions and Required Actions associated with equipment affected by the loss of C540. The purpose for entry into these related specifications is discussed below.

ACTIONS (continued)

C.1 (continued)

LCO 3.3.11, "Emergency Feedwater Initiation and Control (EFIC) System Instrumentation," requires all associated instruments that are used to perform actuation or vector functions within the EFIC system to be OPERABLE. A loss of power to C540 will result in the green train SG level and pressure inputs from both SGs to fail to zero. The zero signals will result in a half trip of EFIC. Therefore, entry into LCO 3.3.11 Condition A is appropriate. Should an actual actuation occur while C540 is de-energized, the vector logic, receiving zero inputs from SG pressure instrumentation, will not isolate flow from the green EFW train to either SG upon a steam line break event. Therefore, entry into LCO 3.3.11 Condition C is also appropriate. However, both the EFIC actuation logic and the EFIC vector logic continue to function as designed, based on the inputs they are receiving. Because these logics continue to function and because LCO 3.3.11 Condition C provides an acceptable restoration period for instrumentation that affects the overall vector logic response, it is not necessary to enter the Conditions or Required Actions of LCO 3.3.13, "Emergency Feedwater Initiation and Control (EFIC) Logic" or LCO 3.3.14, "Emergency Feedwater Initiation and Control (EFIC) Vector Logic." Likewise, the EFW system remains functional, responding according to the inputs received from the actuation and vector logic subsystems. Therefore, entry into LCO 3.7.5, "Emergency Feedwater (EFW) System," is not required. The loss of power to C540 does not prevent manual control of the green EFW train and does not affect the OPERABILITY of the red EFW train.

LCO 3.3.15, "Post Accident Monitoring (PAM) Instrumentation," requires specific instrumentation to be available to the operators following an accident. The loss of C540 will result in the loss of one of the PAM-required RCS wide-range pressure and pressurizer level instruments. Therefore, entry into LCO 3.3.15 Condition A is appropriate upon loss of C540.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," requires the automatic closure interlock (ACI) associated with the decay heat removal pump RCS suction valves to be OPERABLE. A loss of C540 renders the ACI function inoperative. Therefore, entry into LCO 3.4.14 Condition B is appropriate.

Other functions and instrumentation are affected by the loss of C540. However, these additional affects do not alone result in a loss of any safety function or violate any technical specification other than those discussed above. Station procedures address these additional components and provide corrective action guidance where appropriate.

ACTIONS (continued)

D.1

With one or more DC subsystems inoperable, the remaining OPERABLE portions of the DC electrical power distribution subsystems may be 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 ES functions not being supported. Therefore, the DC buses must be restored to OPERABLE status within 8 hours by powering the bus from the associated battery or one of the two associated chargers.

Condition D represents one or more DC subsystem(s) 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 8 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 8 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while 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

c. The potential for an event in conjunction with a single failure of a redundant component.

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition D is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 16 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

ACTIONS (continued)

E.1 and E.2

If the inoperable distribution subsystem 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 12 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.

F.1

Condition E corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. 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 120 VAC bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained. The 7 day Frequency takes into account the redundant capability of the AC, DC, and 120 VAC bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. SAR, Chapter 14.

2. 10 CFR 50.36.

Table B 3.8.9-1

AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	RED TRAIN	GREEN TRAIN
AC safety buses	4160 V 480 V 480 V	ES Bus A3 Load Center B5 Motor Control Centers B51, B52, B53, B57	ES Bus A4 Load Center B6 Motor Control Centers B61, B62, B63, B65, B56** and B55
DC buses	125 V	Bus D01 Bus RA1 Distribution Panel D11	Bus D02 Bus RA2 Distribution Panel D21
120 VAC distribution panels	120 V	Panel RS1 Panel RS3	Panel RS2 Panel RS4 Panel C540

* Each train of the AC and DC electrical power distribution systems is a subsystem.

** Swing bus (normally associated with Green Train). Bus B55 is powered from Bus B56.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems – Shutdown

BASES

BACKGROUND

A description of the AC, DC and 120 VAC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The AC, DC, and 120 VAC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, and reliability to ensure the availability of necessary power to ES systems.

The OPERABILITY of the minimum AC, DC, and 120 VAC 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 MODE 5 or 6 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 a postulated fuel handling accident.

In MODES 5 and 6, the AC and DC electrical power distribution systems satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1). During handling of irradiated fuel, the AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36.

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by LCO 3.3.9, "Source Range Neutron Flux," LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled," LCO 3.4.11, "Low Temperature Overpressure (LTOP) Protection System," LCO 3.7.9, "Control Room Emergency Ventilation System (CREVS)," LCO 3.7.10, "Control Room Emergency Air Conditioning System (CREACS)," LCO 3.7.12, "Fuel Handling Area Ventilation System (FHAVS)," LCO 3.9.2, "Nuclear Instrumentation" (for one monitor only), LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation," and LCO 3.9.5,

LCO (continued)

"Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level" depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support features. This LCO requires energization of the portions of the electrical 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.

Maintaining these portions of the distribution system OPERABLE ensures the availability of sufficient power to operate the unit in a safe manner.

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 in either the reactor building or fuel handling area, provide assurance that:

a. Systems to provide adequate decay heat removal are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident in either the reactor building or fuel handling area 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 MODES 5 or 6.

The AC, DC, and 120 VAC 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 would not specify an 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.

ACTIONS (continued)

A.1, A.2.1, A.2.2, A.2.3, A.2.4, A.2.5, and A.2.6

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 CORE ALTERATIONS and 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 CORE ALTERATIONS, movement of irradiated fuel assemblies in both the reactor building and the fuel handling area, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). 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 which 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 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 a fuel handling accident. 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 or a required low temperature overpressure protection (LTOP) feature may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation, heat removal and LTOP. Pursuant to LCO 3.0.6, the DHR ACTIONS and LTOP ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring DHR inoperable, which results in taking the appropriate DHR actions and Required Action A.2.6 is provided to direct entry into the appropriate LTOP Conditions and Required Actions, which results in taking the appropriate LTOP actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the required AC, DC, and 120 VAC vital bus electrical power distribution subsystems are functioning properly, with all the buses energized. 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.

REFERENCES

1. 10 CFR 50.36.

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. The refueling boron concentration is specified for the coolant in each of these volumes since each volume has 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 specified in the COLR ensures an overall core reactivity of $k_{eff} \leq 0.99$ during fuel handling, with all CONTROL RODS out.

SAR, Section 1.4, GDC 26 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 has the ability to initiate and maintain a cold shutdown condition in the reactor.

During refueling, the spent fuel pool, the transfer tube, the refueling canal and the reactor vessel are connected. As a result, the soluble boron concentration is relatively the same in each of these volumes.

Operation of the Decay Heat Removal (DHR) System in the RCS mixes 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, "Decay Heat Removal (DHR) and Coolant Circulation," and LCO 3.9.5, "Decay Heat Removal (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.

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. 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.

APPLICABLE SAFETY ANALYSES (continued)

The required boron concentration and the unit refueling procedures ensure the k_{eff} of the core will remain ≤ 0.99 during the refueling operation.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36. (Ref. 2).

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 ≤ 0.99 is maintained during fuel handling operations with CONTROL RODS and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by unit procedures.

Violation of the LCO provides a potential for 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.

Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," LCO 3.1.5, "Safety Rod Insertion Limits," and LCO 3.2.1, "Regulating Rod Insertion Limits," 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 that volume is connected to the Reactor Coolant System. When the refueling canal is isolated from the RCS, no potential path for boron dilution exists.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of the RCS or the refueling canal is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

ACTIONS (continued)

A.1 and A.2 (continued)

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that 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.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, action to restore the concentration must be initiated immediately.

There is no unique design basis event analysis that requires a specific rate of boration. The only requirement is to restore the boron concentration to its required value as soon as possible.

Once actions have been initiated, they 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 the refueling canal is within the COLR limits. The boron concentration of the coolant in each volume is determined every 72 hours 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 cavity was disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

The Frequency is based on industry experience, which has shown 72 hours to be adequate.

REFERENCES

1. SAR, Section 1.4, GDC 26.

2. 10 CFR 50.36.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation (NI) System. These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The use of temporary detectors is permitted, provided the LCO requirements are met.

The installed source range neutron flux monitor channels include fission chamber detectors. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux. The instrumentation also provides continuous visual indication in the control room to alert operators to a significant change in neutron flux. The NI system is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

An OPERABLE source range neutron flux monitor is required to provide indication to alert the operator to unexpected changes in core reactivity, such as may be caused by a boron dilution accident or an improperly loaded fuel assembly (Ref. 1).

The safety analysis of the uncontrolled boron dilution accident is described in Reference 2. The analysis of the uncontrolled boron dilution accident shows that the reactor remains subcritical. The source range neutron flux monitors are not credited for boron dilution event mitigation in the safety analysis.

The source range neutron flux monitors satisfy Criterion 4 of 10 CFR 50.36 (Ref. 3).

LCO

This LCO requires one source range neutron flux monitor OPERABLE to ensure that monitoring capability is available to detect changes in core reactivity. One additional source range neutron flux monitor shall be OPERABLE during CORE ALTERATIONS. This additional requirement ensures redundant monitoring capability when positive reactivity changes are being made to the core. Because neither monitor performs a control function in MODE 6, the power sources supporting the monitors are not required to be uninterruptible or battery-backed.

The use of temporary detectors is permitted for purposes of complying with this LCO. If used, the temporary detectors should be functionally equivalent to the installed source range monitors and satisfy applicable Surveillance Requirements.

APPLICABILITY

In MODE 6, the source range neutron flux monitor 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, source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.9, "Source Range Neutron Flux."

In MODE 1, the neutron flux level is above the indicated range of the monitors. Thus, they are no longer relied upon for reactivity or power level monitoring. Hence, there are no requirements on source range neutron flux monitors in MODE 1.

ACTIONS

A.1 and A.2

With only one required source range neutron flux monitor OPERABLE during CORE ALTERATIONS, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS 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. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position. 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.

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 or until the Applicability is exited.

B.2

With no required source range neutron flux monitor OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made in accordance with Required Actions A.1 and A.2, the core reactivity condition is stabilized until the source range neutron flux monitors are restored to an OPERABLE status. This stabilized condition is verified by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

ACTIONS (continued)

B.2 (continued)

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration. 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 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. Changes in fuel loading and core geometry can also result in significant differences between source range channels, but each channel should be consistent with its local conditions. When in MODE 6 with only one channel OPERABLE, a CHANNEL CHECK is still required. However, in this condition, a redundant source range instrument may not be available for comparison. The CHANNEL CHECK provides verification that the OPERABLE source range channel is energized and indicating a value consistent with current unit status.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified 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 source range nuclear instrument is a complete check and re-adjustment of the channel, from the pre-amplifier input to the indicator. The 18 month Frequency is based on industry experience which has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. SAR, Section 1.4, GDC 13, GDC 26, GDC 28, and GDC 29.

2. SAR, Section 14.1.2.4.

3. 10 CFR 50.36.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Reactor Building Penetrations

BASES

BACKGROUND

During the movement of irradiated fuel assemblies within the reactor building, a release of fission product radioactivity within the reactor building will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, the containment of fission products is accomplished by maintaining the reactor building OPERABLE as described in LCO 3.6.1, "Reactor Building". In MODE 6, the potential for reactor building pressurization as a result of an accident is not likely; therefore, requirements to isolate the reactor building from the outside atmosphere can be less stringent. In order to make this distinction, the penetration requirements are referred to as "reactor building closure" rather than "reactor building OPERABILITY." Reactor building closure means that all potential direct release paths are closed or capable of being closed. Since there is no potential for significant reactor building pressurization, the Appendix J leakage criteria and tests are not required.

The reactor building serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10CFR100. Additionally, the reactor building provides radiation shielding from the fission products that may be present in the reactor building atmosphere following accident conditions.

The reactor building equipment hatch, which is part of the reactor building pressure boundary, provides a means for moving large equipment and components into and out of the reactor building. During the movement of irradiated fuel assemblies within the reactor building, the equipment hatch must be capable of being closed.

During the movement of irradiated fuel assemblies within the reactor building, administrative controls shall ensure that appropriate personnel are aware that the equipment hatch is open, that a specific individual(s) is designated and available to close the equipment hatch cover following a required evacuation of the reactor building, and that any obstruction(s) (e.g., cables and hoses) that could prevent closure of the equipment hatch cover be capable of being quickly removed (Ref. 1). Should a fuel handling accident occur inside the reactor building, the equipment hatch will be closed following evacuation of the reactor building. For closure, the equipment hatch cover will be in place with a minimum of four bolts securing the cover to the sealing surface. During outages, a temporary equipment hatch cover may be used in lieu of the permanent equipment hatch cover (Ref. 2).

BACKGROUND (continued)

The reactor building air locks, which are also part of the reactor building pressure boundary, provide a means for personnel access. During MODES 1, 2, 3, and 4 unit operation is in accordance with LCO 3.6.2, "Reactor Building Air Locks." Each air lock has a door at each end. The doors are normally interlocked to prevent simultaneous opening when the reactor building OPERABILITY is required. During unit shutdown when reactor building OPERABILITY is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods. During the movement of irradiated fuel assemblies within the reactor building, closure requires that one door in each air lock be capable of being closed. The door interlock mechanism may remain disabled.

During the movement of irradiated fuel assemblies within the reactor building, administrative controls shall ensure that appropriate personnel are aware that both personnel airlock doors are open, that a specific individual(s) is designated and available to close an airlock door following a required evacuation of the reactor building, and any obstruction(s) (e.g., cables and hoses) that could prevent closure of an airlock door be capable of being quickly removed (Ref. 3). Should a fuel handling accident occur inside the reactor building, at least one of the personnel and/or emergency air lock doors will be closed following evacuation of the reactor building.

The requirements on reactor building penetration closure ensure that a release of fission product radioactivity from within the reactor building will be restricted to within regulatory limits.

The Reactor Building Purge System includes a supply penetration and exhaust penetration. During MODES 1, 2, 3, and 4, the valves in the supply and exhaust penetrations are secured in the closed position. The system is not subject to a Specification in MODE 5.

In MODE 6, the purge system is used for temperature control, and all four valves may be closed by an operator based on an indication of high radiation. This LCO requires that an OPERABLE radiation monitor be present on the purge exhaust flow path to provide the necessary indication to the operator.

Other reactor building penetrations that provide direct access from the reactor building atmosphere to outside atmosphere must be isolated on at least one side by a closed manual or automatic isolation valve, blind flange, or equivalent, or capable of being isolated by an OPERABLE isolation valve. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure ventilation barrier for the other reactor building penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

During the movement of irradiated fuel assemblies within the reactor building, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 4). The requirements of LCO 3.9.6, "Refueling Canal Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity subsequent to a fuel handling accident results in doses that are within the requirements specified in Reference 4.

Reactor building penetrations satisfy Criterion 4 of 10 CFR 50.36 (Ref. 5).

LCO

This LCO limits the consequences of a fuel handling accident in the reactor building by limiting the potential escape paths for fission product radioactivity from the reactor building. The LCO requires any penetration providing direct access from the reactor building atmosphere to the outside atmosphere to be closed or capable of being closed by an OPERABLE reactor building isolation valve. This LCO requires the reactor building purge isolation valves and the purge exhaust flow path radiation monitor be OPERABLE.

The reactor building personnel airlock doors and/or the equipment hatch may be open during movement of irradiated fuel in the reactor building provided that one door is capable of being closed in the event of a fuel handling accident. Administrative controls shall ensure that appropriate personnel are aware that both personnel airlock doors and/or equipment hatch are open, that a specific individual(s) is designated and available to close an airlock door and the equipment hatch cover following a required evacuation of the reactor building, and any obstruction(s) (e.g. cables and hoses) that could prevent closure of an airlock door and the equipment hatch cover be capable of being quickly removed (Ref. 1 and 3). For closure, the equipment hatch cover will be in place with a minimum of four bolts securing the cover to the sealing surface. During outages, a temporary equipment hatch cover may be used in lieu of the permanent equipment hatch cover (Ref. 2).

The definition of "direct access from the reactor building atmosphere to the outside atmosphere" is any path that would allow for the transport of reactor building atmosphere to any atmosphere located outside of the reactor building structure. This includes the Auxiliary Building. As a general rule, closed systems do not constitute a direct path between the reactor building and the outside environments. All permanent and temporary penetration closures should be evaluated to assess the possibility for a release path to the outside environment. For the purpose of determining what constitutes a "direct access" path, no failure mechanisms should be applied to create a scenario which results in a "direct access" path. For example, line breaks, valve failures, power losses or natural phenomenon should not be postulated as part of the evaluation process.

APPLICABILITY

The reactor building penetration requirements are applicable during movement of irradiated fuel assemblies within the reactor building because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, the reactor building penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when movement of irradiated fuel assemblies within the reactor building is not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on reactor building penetration status.

ACTIONS

A.1

With the reactor building equipment hatch, air locks, or any reactor building penetration that provides direct access from the reactor building atmosphere to the outside atmosphere not in the required status, the unit must be placed in a condition in which the isolation function is not needed. This is accomplished by immediately suspending movement of irradiated fuel assemblies within the reactor building. Performance of this action shall not preclude moving a component to a safe position.

These actions remove the potential for an event which may require reactor building closure to prevent a significant radioactivity release.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the reactor building penetrations required to be in its closed position is in that position.

The Surveillance is performed every 7 days during the movement of irradiated fuel assemblies within the reactor building. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations.

This Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the reactor building will not result in a release of fission product radioactivity to the environment in excess of that recommended by Standard Review Plan Section 15.7.4 (Ref. 1, 3 and 6).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.3.2

This Surveillance demonstrates that each reactor building isolation valve actuates to its isolation position on manual initiation. The 18 month Frequency maintains consistency with other similar reactor building isolation valve testing requirements found in Section 3.6. This Surveillance will ensure that the isolation valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the reactor building.

The SR is modified by a Note stating that this surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability.

SR 3.9.3.3

This SR requires a CHANNEL CALIBRATION of the reactor building purge exhaust radiation monitor. The CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The CHANNEL CALIBRATION is performed consistent with the setpoint requirements. The 18 month Frequency is based on operating experience and is consistent with the typical operating cycle.

REFERENCES

1. Safety Evaluation Report related to ANO-1 Amendment No. 195, April 16, 1999.

2. SAR, Section 5.2.2.1.3.

3. Safety Evaluation Report related to ANO-1 Amendment No. 184, September 20, 1996.

4. SAR, Section 14.2.2.3.

5. 10 CFR 50.36.

6. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Decay Heat Removal (DHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purposes of the DHR System in MODE 6 are to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34 (Ref. 1), and to provide mixing of the reactor coolant to prevent boron stratification (Ref. 2). Heat is removed from the RCS by circulating reactor coolant through the DHR heat exchanger(s), where the heat is transferred to the Service Water System. The coolant is then returned to the reactor vessel via the core flood tank injection 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 heat exchanger(s), bypassing the heat exchanger(s) and throttling of Service Water through the heat exchanger(s). Mixing of the reactor coolant is provided by the continuous operation of the DHR System.

APPLICABLE SAFETY ANALYSES

Without a DHR loop in operation, the reactor coolant temperature may not be maintained below the boiling point. This could lead to inadequate cooling of the reactor fuel as a result of a loss of coolant in the reactor vessel due to boiling. The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Operation of one train of the DHR System in MODE 6 is sufficient to prevent this challenge. The LCO does permit de-energizing the DHR pump for short durations under the condition that the boron concentration is not reduced. This conditional de-energizing 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 (Ref. 3).

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 fuel assemblies seated in the reactor pressure vessel. The operating DHR loop provides:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

LCO (continued)

To be considered OPERABLE, a DHR loop includes a DHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the temperature. The flow path starts in the 'A' hot leg and is returned to the reactor vessel via the core flood tank injection nozzles.

Additionally, to be considered OPERABLE, each DHR loop must be capable of being manually aligned (remote or local) in the decay heat removal 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 cause 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 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 allowance permits operations such as core mapping, alterations or maintenance in the vicinity of the reactor vessel 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 fuel assemblies seated in the reactor pressure vessel, 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), and Section 3.5, Emergency Core Cooling Systems (ECCS). DHR loop requirements in MODE 6, with the water level < 23 feet above the top of the fuel assemblies seated in the reactor vessel, are located in LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level."

ACTIONS

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 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.

ACTIONS (continued)

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 canal water level 23 feet above the fuel assemblies seated in the reactor vessel provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading an irradiated 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.

Restoration of one decay heat removal loop is required because this is the only active method of removing decay heat. Dissipation of decay heat through natural convection to the large inventory of water in the refueling canal should not be relied upon for an extended period of time. The immediate Completion Time reflects the importance of restoring an adequate decay heat removal loop.

A.4

If DHR loop requirements are not met, all reactor building penetrations providing direct access from the reactor building atmosphere to outside atmosphere shall be closed within 4 hours.

If no means of decay heat removal can be restored, the core decay heat could raise temperatures and cause boiling in the core which could result in increased levels of radioactivity in the reactor building atmosphere. Closure of the penetrations providing access to the outside atmosphere will prevent the uncontrolled release of radioactivity to the environment.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the DHR loop is in operation and circulating reactor coolant. Verification includes flow, temperature, or pump status monitoring, which help assure that forced flow is providing heat removal. 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. SAR, Section 1.4.

2. SAR, Section 9.5.

3. 10 CFR 50.36.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Decay Heat Removal (DHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purposes of the DHR System in MODE 6 are to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34 (Ref. 1), and to provide mixing of the reactor coolant to prevent boron stratification (Ref. 2). Heat is removed from the RCS by circulating reactor coolant through the DHR heat exchanger(s), where the heat is transferred to the Service Water System. The coolant is then returned to the reactor vessel via the core flood tank injection 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 heat exchanger(s), bypassing the heat exchanger(s) and by throttling of Service Water through the heat exchanger(s). Mixing of the reactor coolant is provided by the continuous operation of the DHR System.

APPLICABLE SAFETY ANALYSES

Without a DHR loop in operation, the reactor coolant temperature may not be maintained below the boiling point. This could lead to inadequate cooling of the reactor fuel as a result of a loss of coolant in the reactor vessel due to boiling. The loss of reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Operation of one train of the DHR System in MODE 6 is sufficient to prevent this challenge. However, without a large water inventory to provide a backup means of decay heat removal, an additional train of the DHR System is required to be OPERABLE in order to provide a backup.

The DHR System satisfies Criterion 4 of 10 CFR 50.36 (Ref. 3).

LCO

In MODE 6, with the water level < 23 feet above the top of the fuel seated in the reactor vessel, two DHR loops must be OPERABLE. Additionally, one DHR loop must be in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

LCO (continued)

This LCO is modified by two Notes. Note 1 permits the DHR pumps to be de-energized 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 temperature is maintained > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when DHR forced flow is stopped.

The second Note 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 that the core time to boil is short, there is no draining operation to further reduce RCS water level and that capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

To be considered OPERABLE, a DHR loop must consist of a DHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the temperature. The flow path starts in the 'A' hot leg and is returned to the reactor vessel via the core flood tank injection nozzles.

Additionally, to be considered OPERABLE, each DHR loop must be capable of being manually aligned (remote or local) in the decay heat removal mode for removal of decay heat. Operation of one subsystem can maintain the reactor coolant temperature as required.

Both DHR pumps may be aligned to the Borated Water Storage Tank (BWST) to support filling of the refueling canal or the performance of required testing.

APPLICABILITY

Two DHR loops are required to be OPERABLE, and one in operation in MODE 6, with the water level < 23 feet above the top of the fuel seated in the reactor vessel, 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), and Section 3.5, Emergency Core Cooling Systems (ECCS). DHR loop requirements in MODE 6 are located in LCO 3.9.4.

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 feet of water level is established above the fuel seated in the reactor vessel. When the water level is established at ≥ 23 feet above the fuel seated in the reactor vessel, 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 due to the increased risk of operating without a large available heat sink.

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 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 without interruption to restore one DHR loop to OPERABLE status and operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE DHR loops and one operating DHR loop should be accomplished expeditiously.

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 fuel assemblies seated in the reactor vessel. 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. 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.

ACTIONS (continued)

B.3

If no DHR loop is in operation, all reactor building penetrations providing direct access from the reactor building atmosphere to the outside atmosphere must be closed within 4 hours. With the DHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the reactor building atmosphere. Closing reactor building penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours 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. Verification includes flow rate, temperature, or pump status monitoring, which help assure that forced flow is providing heat removal.

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 each required pump is available 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. Alternatively, verification that a DHR pump is in operation as required by SR 3.9.4.1 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.

REFERENCES

1. SAR, Section 1.4.

2. SAR, Section 9.5.

3. 10 CFR 50.36.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Canal Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within the reactor building requires a minimum water level of 23 feet above the top of the irradiated fuel assemblies seated within the reactor pressure vessel. During refueling, this maintains sufficient water level 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 and the refueling cavity is an initial condition design parameter in the analysis of the fuel handling accident in the reactor building postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 feet above the top of the irradiated fuel assemblies seated within the reactor pressure vessel (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 12% of the total fuel rod iodine inventory (Ref. 2).

The fuel handling accident analysis inside the reactor building is described in Reference 2. With a minimum water level of 23 feet above the top of the irradiated fuel assemblies seated within the reactor pressure vessel, and a minimum decay time of 100 hours prior to fuel handling, the analysis demonstrates 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 (Ref. 4).

LCO

A minimum refueling canal water level of 23 feet above the top of the irradiated fuel assemblies seated in the reactor pressure vessel is required to ensure that the radiological consequences of a postulated fuel handling accident inside the reactor building are within acceptable limits as provided by 10 CFR 100.

APPLICABILITY

LCO 3.9.6 is applicable during movement of irradiated fuel assemblies within the reactor building. The LCO minimizes the possibility of a fuel handling accident in the reactor building that is beyond the assumptions of the safety analysis. If irradiated fuel is not present in the reactor building, there can be no significant radioactivity release as a result of a postulated fuel handling accident in the reactor building.

ACTIONS

A.1

With a water level of < 23 feet above the top of the irradiated fuel assemblies seated with the reactor pressure vessel, all operations involving the movement of irradiated fuel assemblies shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of irradiated 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 feet above the top of the irradiated fuel assemblies seated within the reactor pressure vessel 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 irradiated fuel assemblies seated within the reactor pressure vessel limits the consequences of damaged fuel rods that are postulated to result from a postulated fuel handling accident inside the reactor building (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, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.

2. SAR Section 14.2.2.3.

3. 10 CFR 100.10.

4. 10 CFR 50.36.