TECHNICAL SPECIFICATIONS BASES

FOR

COMANCHE PEAK STEAM ELECTRIC STATION

UNITS 1 AND 2

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

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

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

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

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

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

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APPLICABLE SAFETY ANALYSES (continued)

a. There must be at least 95% probability at a 95% confidence level (the 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 centerline fuel melting.

The Reactor Trip System Allowable Values in Table 3.3.1-1, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Protection for these reactor core SLs is provided by the appropriate operation of the RPS and the steam generator safety valves.

The SLs represent a design requirement for establishing the RPS Allowable Values identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," and the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The reactor core SLs are established to preclude violation of the following fuel design criteria:

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

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature N-16 reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation.

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BASES

SAFETY LIMITS (continued)

Appropriate functioning of the RPS and the steam generator safety valves ensure that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs. Limits on process variables are developed both to protect the reactor core SLs and for compliance with the additional restrictions on hot leg enthalpy and vessel exit quality. The Reactor Core Safety Limit figures, provided in the COLR, reflect these process variable limits.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Allowable Values for the reactor trip functions are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." 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. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

Per 10CFR50.36, if a Safety Limit is violated, operations must not be resumed until authorized by the Commission.

REFERENCES

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

2. FSAR, Chapter 7.

3. “Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology,” RXE-90-006-P-A, June 1994.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor pressure coolant boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), 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 2485 psig. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% (3107 psig) of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could 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. 4).

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to 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%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a turbine trip without a direct reactor trip. Safety valves on the secondary side are assumed to open when the steam pressure reaches the safety valve settings. Main feedwater supply is lost at the time of turbine trip.

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APPLICABLE SAFETY ANALYSES (continued)

The Reactor Trip System Allowable Values in Table 3.3.1-1, together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization. The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

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

a. Pressurizer power operated relief valves (PORVs);

b. Steam Generator Atmospheric Relief Valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valves.

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure.

The SL on maximum allowable RCS pressure is 2735 psig.

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 due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

SAFETY LIMIT VIOLATION

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. 4).

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BASES

SAFETY LIMIT VIOLATION (continued)

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

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 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. The 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.

Per 10CFR50.36, if a Safety Limit is violated, operations must not be resumed until authorized by the Commission.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and GDC 28.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWX-5000.
4. 10 CFR 100.
5. FSAR, Chapter 7.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs

LCO 3.0.1 through LCO 3.0.6 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even

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BASES

LCO 3.0.2 (continued)

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. The 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.

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BASES

LCO 3.0.3 (continued)

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

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

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

a. The LCO is now met.

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

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 Specification 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

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BASES

LCO 3.0.3 (continued)

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.

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 3.7.15, "Fuel Storage Area Water Level." LCO 3.7.15 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage area." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.15 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 3.7.15 of "Suspend movement of irradiated fuel assemblies in the fuel storage 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 allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b or LCO 3.0.4.c.

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

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LCO 3.0.4 (continued)

MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

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

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

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

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

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LCO 3.0.4 (continued)

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

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

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

The provisions of LCO 3.0.4 shall not prevent 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. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable

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LCO 3.0.4 (continued)

Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

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

LCO 3.0.5

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

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

b. The OPERABILITY of other equipment.

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

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

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

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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.

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

Specification 5.5.15, "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.

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BASES

LCO 3.0.6 (continued)

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 redundant OPERABLE support system 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.

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 LCO 3.1.8, allows 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 not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. 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. Upon completion of maintenance, appropriate post maintenance testing is required to declare

(continued)

BASES

SR 3.0.1 (continued)

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.

SR 3.0.2

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

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS.

Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by the TS, and the SR include a Note in the Frequency stating, “SR 3.0.2 is not applicable.” An example of an exception when the test interval is not specified in the regulations is the

Note in the Containment Leakage Rate Testing Program, “SR 3.0.2 is not applicable.” This exception is provided because the program already includes extension of test intervals.

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

(continued)

BASES

SR 3.0.2 (continued)

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 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 not to have been performed when specified, SR 3.0.3 allows the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

(continued)

BASES

SR 3.0.3 (continued)

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." The 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. 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.

(continued)

BASES

SR 3.0.4

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

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

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

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

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

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and

(continued)

BASES

SR 3.0.3 (continued)

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. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are satisfied by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Rod Control System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Rod Control System, together with the Chemical and Volume Control System (CVCS), provides the SDM during power operation and is capable of making the core subcritical, assuming that the rod of highest reactivity worth remains fully withdrawn. The CVCS can control the soluble boron concentration to compensate for fuel depletion during operation and all xenon burnout reactivity changes and can maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

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

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

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

The most limiting accidents for the SDM requirements area main steam line break (MSLB) and boron dilution accidents, as described in the accident analysis (Ref. 2).

The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As the initial RCS temperature decreases, the severity of an MSLB decreases until MODE 5 is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest. The shutdown margin must be adequate to allow sufficient time for the reactor operators to detect an inadvertent boron dilution and initiate appropriate action to prevent a complete loss of shutdown margin.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

SDM satisfies Criterion 2 of 10CFR50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB and the boron dilution accidents (Ref. 2) are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be available. The required SDM is specified in the COLR.

APPLICABILITY

In MODE 2 with $k_{eff} < 1.0$ and in MODES 3, 4 and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, “Control Bank Insertion Limits.”

The Applicability is modified by a Note stating that the transition from MODE 6 to MODE 5 is not permitted while LCO 3.1.1 is not met. This Note specifies an exception to LCO 3.0.4 and prohibits the transition when SDM limits are not met. This Note assures that the initial assumptions of a postulated boron dilution event in MODE 5 are met.

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 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

(continued)

BASES

ACTIONS

A.1 (continued)

possible, the borated water source should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 2 (with k_{eff} < 1.0), 3, 4 and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Shutdown and Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

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

In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

(continued)

BASES (continued)

REFERENCES	1.	10 CFR 50, Appendix A, GDC 26.
	2.	FSAR, Chapter 15.
	3.	Not Used.
	4.	10 CFR 100.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

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 anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN") in ensuring the reactor can be brought safely to cold, subcritical conditions.

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

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

(continued)

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES

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

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

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

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

Core reactivity satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily altered once the core design is fixed. During operation, therefore, 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 DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of $\pm$ 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

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

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration")

(continued)

BASES

APPLICABILITY (continued)

ensure that fuel movements are performed within the bounds of the safety an analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

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

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

B.1

If the core reactivity cannot be restored to within the 1% Δ/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve

(continued)

BASES

ACTIONS

B.1 (continued)

this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by LCO 3.1.1 Required Action A.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note requires that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. However, if the deviation between measured and predicted values is within the associated measurement and analytical uncertainties, it is not necessary to normalize the predicted core reactivity. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPD, following the initial 60 EFPD after entering MODE 1, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.

2. FSAR, Chapter 15.

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 its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over most of the fuel cycle. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Reload cores are designed so that the beginning of cycle (BOC) MTC is less than zero when THERMAL POWER is at RTP. 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 fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the FSAR accident and transient analyses.

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits,

(continued)

BASES

BACKGROUND (continued)

since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

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

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

The FSAR, Chapter 15 (Ref. 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 important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 2).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase, sudden decrease in feedwater temperature, and steam line break.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at Rated Thermal Power or zero power, and whether it is the BOC or EOC. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOC and EOC. An EOC measurement is conducted at conditions when the RCS reaches a boron concentration equivalent to 300 ppm at an equilibrium, all rods out, RTP condition. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

MTC satisfies Criterion 2 of 10CFR50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that 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.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and less negative than a given lower bound. The MTC is most positive near BOC; this upper bound must not be exceeded. This maximum upper limit occurs near BOC, all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. This limit is defined to be +5pcm/°F for power levels up to 70% RTP and a linear ramp from that point to 0 pcm/°F at 100% RTP for the all rods withdrawn, beginning of cycle life (BOL) condition. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis.

(continued)

BASES

APPLICABILITY (continued)

The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOC MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

In general, as cycle burnup is increased, the RCS boron concentration will initially be increased to accommodate a PMTC (between roughly 150-3000 MWd/MTU, depending on cycle energy requirements, burnable absorbers, etc.) and then will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with k_{eff} < 1.0 to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be brought to a

(continued)

BASES

ACTIONS

C.1 (continued)

MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOC MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO requires that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, 60 ppm and 300 ppm SR values of MTC should necessarily be less negative than the EOC LCO limit. The 60 ppm and 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to ensure that the LCO limit will be met when the Surveillance criterion is met.

The 60 ppm and 300 ppm SR values are determined consistent with a natural (fresh) Boron-10 (B-10) isotopic abundance in the RCS boron.

During normal operation, neutron, neutron absorption reduces the fraction of B-10 in the RCS boron concentration. When the plant operates at steady state full power during the cycle, boration is generally not required and the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

B-10 is not replenished. A B-10 depletion model that accounts for the reduction in the B-10 isotopic abundance may be used to adjust the measured boron concentration to be more consistent with the calculational basis of the SR values.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

1. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. The measured equilibrium boron concentration should be adjusted to RTP, ARO conditions and may be adjusted for B-10 isotopic abundance. Normally, the measured concentration will be greater than the adjusted concentration near this time in cycle life. The SR should not be performed prior to the adjusted concentration indicating ≤ 300 ppm. The SR shall be performed prior to exceeding 7 EFPDs after achieving an adjusted concentration of 300 ppm.

2. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days (EFPDs) is sufficient to avoid exceeding the EOC limit.

3. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.

2. FSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," 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 rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

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

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among four control banks and five shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs typically consists of two groups that are moved in a staggered fashion, but always within one step of each other.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with

(continued)

BASES

BACKGROUND (continued)

control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the accuracy of the DRPI System will be reduced by half.

The DRPI system is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 3). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. An additional analysis is performed in which all rods but one are assumed to be fully withdrawn; the remaining rod is assumed to be fully inserted. Satisfying limits on departure from nucleate boiling ratio in these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 3).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified

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BASES

APPLICABLE SAFETY ANALYSES (continued)

directly by core power distribution measurement. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements (i.e., trippability to meet SDM) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. A rod is considered OPERABLE based on the last satisfactory performance of SR 3.1.4.2 and has met the rod drop time criteria during the last performance of SR 3.1.4.3. Rod control malfunctions that result in the inability to move a rod (e.g., rod urgent failures), which do not impact trippability within the time requirements of SR 3.1.4.3, do not result in rod inoperability.

The requirement to maintain the rod alignment to within plus or minus 12 steps of their group step counter demand position is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

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

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2, because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the rods are typically fully inserted and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect

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BASES

APPLICABILITY (continued)

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 2 with k_{eff} < 1.0, 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e.,untrippable), 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 boration to restore SDM. It is assumed that boration will continue until SDM requirements are met.

In this situation, SDM verification must include the worth of the untrippable rod (at its present position or greater (e.g., full out), to ensure the position used is conservative with respect to SDM verification), as well as the rod of maximum worth.

A.2

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

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

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable (i.e., OPERABLE). If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction.

An alternative to realigning a single misaligned RCCA to the group demand position is to align the remainder of the group to the position of the

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BASES

ACTIONS

B.1 (continued)

misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit. Verification of shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, “CONTROL BANK INSERTION LIMITS” ensure SDM is maintained provided the misaligned rod is above the insertion limits.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be fully inserted and control bank C must be inserted to approximately 100 to 115 steps.

Power operation may continue with one RCCA OPERABLE (i.e., trippable) but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration. It is assumed that boration will continue until SDM requirements are met.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, reactor power must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 3) The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

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

(continued)

BASES

ACTIONS

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6 (continued)

Verifying that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain a core power distribution measurement and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of the affected accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in FSAR Chapter 15 (Ref. 3) that may be adversely affected will be evaluated to ensure that the analyses results remain valid for the duration of continued operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions of Condition B cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group demand position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. Verification of shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, “CONTROL BANK INSERTION LIMITS” ensure SDM is maintained provided the misaligned rod is above the insertion limit. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 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 to align the required valves and start the required pumps. Boration will continue until the required SDM is restored.

(continued)

BASES

ACTIONS (continued)

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. 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, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. If the rod position deviation monitor is inoperable, the Frequency is increased to 4 hours per TRM requirement TRS 13.1.37.1 which accomplishes the same goal. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. 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 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between or during required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable, the control rod(s) is considered to be OPERABLE until the surveillance interval expires. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature $\geq$ 500°F to simulate a reactor trip under actual conditions.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.

2. 10 CFR 50.46.

3. FSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, 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 control 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 preserved.

The rod cluster control assemblies (RCCAs) are divided among four control banks and five shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs typically consists of two groups that are moved in a staggered fashion, but always within one step of each other. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks can be automatically controlled by the Rod Control System or manually controlled by the reactor operators. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power 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. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative

(continued)

BASES

BACKGROUND (continued)

reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

    1. specified acceptable fuel design limits, or

    2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

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BASES (continued)

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODE 1 and in Mode 2 with any control bank not fully inserted. The applicability in MODE 2 begins prior to initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are typically fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 2 with $k_{eff} < 1.0$, 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

<u>A.1.1, A.1.2 and A.2</u>

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1. When boration is initiated to restore SDM to within limits, it is assumed that boration will continue until SDM requirements are met.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

(continued)

BASES

ACTIONS

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

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to MODE 3 where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are within limits during a unit startup and subsequent operation.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours is adequate to ensure that they are within their insertion limits. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28.

2. 10 CFR 50.46.

3. FSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

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

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, 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 control 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 preserved.

The rod cluster control assemblies (RCCAs) are divided among four control banks and five shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit lines.

The COLR figure also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The fully withdrawn position is defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks can be controlled automatically by the Rod Control System, or manually by the reactor operators. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, LCO 3.2.3, "AXIAL FLUX DIFFERENCE

(continued)

BASES

BACKGROUND (continued)

(AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

Implicit in all calculations which involve the bank insertion limits is the assumption that normal control bank sequence and overlap are maintained.

The insertion limits satisfy Criterion 2 of 10CFR50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

(continued)

BASES (continued)

ACTIONS

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

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. When boration is initiated to restore SDM to within limits, it is assumed that boration will continue until SDM requirements are met. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits. For Required Action B.1.1, verification of shutdown banks fully withdrawn and control banks within the insertion limits ensure SDM is maintained.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 3, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical condition (ECC) depends upon a number of factors, one of which is xenon concentration. If the ECC was calculated long before criticality, xenon concentration could change to make the ECC substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECC calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECC calculation with other startup activities.

SR 3.1.6.2

Verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to ensure OPERABILITY and to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

SR 3.1.6.3

There is a potential that, with only a limit on rod insertion, the RCCAs could be placed in a sequence or overlap position, perhaps during troubleshooting activities or other abnormal plant conditions, that would violate core flux peaking factors while still satisfying the limits on rod insertion. This scenario is most likely to occur at reduced power following an automatic runback or due to an administrative power reduction in response to some rod control abnormality.

This surveillance ensures that the rod configuration across the core for any given operating condition will not result in unanalyzed peaking factors. The surveillance is not designed to test or verify the function of the Rod Control sequence and overlap circuits. In practice, this surveillance will be satisfied as long as the rod positions are in the positions specified in the COLR, regardless of the operability of the sequence and overlap circuits. The intent is to check the rod position to verify that the rods are in the expected positions as described in the COLR. If all rods are out of the core when the check is made, then rod sequence and overlap limits are satisfied for the purpose of this surveillance. At all power levels, the rod positions should conform to the requirements of the COLR for rod sequence and overlap. Implicit within the LCO is the assumption that bank sequence and overlap

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.3 (continued)

must be maintained during rod movement. When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, GDC 28.
2. 10 CFR 50.46.
3. FSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

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

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

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each

(continued)

BASES

BACKGROUND (continued)

group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the DRPI will go on half accuracy. The DRPI System is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of 10CFR50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that the DRPI System and Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The DRPI System, on either full accuracy or half accuracy, indicates within 12 steps of the group step counter demand position as

(continued)

BASES

LCO (continued)

required by LCO 3.1.4, "Rod Group Alignment Limits"; and

b. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

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

APPLICABILITY

The requirements on the DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5 and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator. The note applies to an inoperable rod position indication (DRPI) on a “per group” basis and the demand position indication on a “per bank” basis. Applying the note to a “per group” and “per bank” basis is appropriate since the only Conditions available for DRPI are “per group” (Conditions A and B), and for demand indication is “per bank” (Condition D).

(continued)

BASES

ACTIONS (continued)

A.1

When one DRPI per group fails, the position of the rod may still be indirectly determined by use of the incore movable detectors or an OPERABLE PDMS. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1 or C.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 2).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3 and B.4

When more than one DRPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Together with the indirect position determination available via movable incore detectors will minimize the potential for rod misalignment.

The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition. Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

(continued)

BASES

ACTIONS

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

The position of the rods may be determined indirectly by use of the movable incore detectors or an OPERABLE PDMS. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Verification of RCCA position once per 8 hours is adequate for allowing continued full power operation for a limited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the DRPI system to operation while avoiding the plant challenges associated with a shutdown without full rod position indication (Ref. 4).

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Action of C.1 or C.2 below is required.

C.1 and C.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 and A.2 or B.3 are still appropriate but must be initiated promptly under Required Action C.1 to begin indirectly verifying that these rods are still properly positioned, relative to their group positions using the movable incore detectors.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

D.1.1 and D.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the DRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means (e.g., observation of appropriate DRPI status indications) that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

(continued)

BASES

ACTIONS (continued)

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits (Ref. 3). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

E.1

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

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the DRPI agrees with the demand position within 12 steps ensures that the DRPI is operating correctly. Verification at 24, 48, 120, and 228 steps for the control banks and at 18, 210, and 228 steps for the shutdown banks provides assurance that the DRPI is operating correctly over the full range of indication. Since the DRPI does not display the actual shutdown rod positions between 18 and 210 steps, only points within the indicated ranges are required in comparison.

This surveillance is performed prior to reactor criticality after each removal of the reactor vessel head, since there is potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13.

2. FSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

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

a. Ensure that the facility has been adequately designed;

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

c. Verify the assumptions used to predict unit response;

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

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

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, 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.

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the 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.

(continued)

BASES

BACKGROUND (continued)

The PHYSICS TESTS required for reload fuel cycles in MODE 2 typically include:

a. Critical Boron Concentration;

b. Control Rod Worth and

c. Isothermal Temperature Coefficient (ITC).

These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Core Operating Limits Report. The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

The FSAR defines requirements for testing of the facility, including PHYSICS TESTS. Reload fuel cycle PHYSICS TESTS are performed in accordance with Technical Specification requirements, fuel vendor guidelines, and established industry standards and practices. Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must 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 requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)", LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 541°F, and SDM is within the limits specified in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

during PHYSICS TESTS meet Criteria 1, 2, and 3 of the 10 CFR 50.36(c)(2)(ii).

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, 3.1.4, LCO 3.1.5, LCO 3.1.6 and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest operating loop average temperature is ≥ 541°F;

b. SDM is within the limits specified in the COLR; and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

If the SDM requirement is 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 plant conditions. Boration will be continued until SDM is within limit.

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

(continued)

BASES

ACTIONS (continued)

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest operating loop T_{avg} is < 541°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 541°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest operating loop T_{avg} is ≥ 541°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.2 (continued)

during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of the THERMAL POWER at a Frequency of 1 hour during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

Verification that the SDM is within limits specified in the COLR ensures that, for the specific RCCA and RCS temperature manipulations performed during PHYSICS TESTS, the plant is not operating in a condition that could invalidate the safety analysis assumptions. The SDM verification can be facilitated through the use of tables prepared by the core designers in which the reactivity effects expected during the Physics Testing have been previously considered.

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

a. RCS boron concentration;

b. Shutdown and Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

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

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.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50.59.
3. Regulatory Guide 1.68, Revision 2, August, 1978.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (CAOC-W(Z) Methodology)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ 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 fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3.1, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT TILT POWER RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.7, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. The results of the three-dimensional power distribution map are analyzed to derive a measured value for $F_Q(Z)$. These measurements are generally taken with the core at or near equilibrium conditions.

However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ that are present during non-equilibrium situations, such as load following. To account for these possible variations, the steady state value of $F_Q(Z)$ is adjusted by an elevation dependent factor, W(Z), that accounts for calculated transient conditions.

Core monitoring and control under non-steady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

APPLICABLE SAFETY ANALYSES

This LCO's principal effect is to preclude core power distributions that could lead to violation of the following fuel design criterion:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1); and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm.

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the LOCA peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of the 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \le \frac{F_Q^{RTP}}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{F_Q^{RTP}}{0.5} K(Z) \qquad \text{for } P \le 0.5$$

where: F_Q^{RTP} is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

The actual values of F_Q^{RTP} and K(Z) are given in the COLR.

For Constant Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

(continued)

BASES

LCO (continued)

An $F_Q^C(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$.

The computed heat flux hot channel factor, $F_Q^C(Z)$, is obtained by the equation:

$$F_Q^C(Z) = F_Q^M(Z) \cdot 1.03 \cdot 1.05.$$

$F_Q^M(Z)$ is increased by 3% to account for manufacturing tolerances and further increased by 5% to account for measurement uncertainties.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z) \cdot W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients during normal operations. W(Z) is included in the COLR.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. If $F_Q(Z)$ cannot be maintained within the LCO limits, a reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ may produce unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

(continued)

BASES

LCO (continued)

If the power distribution measurements are performed at a power level less than 100% RTP, then the $F_Q^C(Z)$ and $F_Q^W(Z)$ values that would result from measurements if the core was at 100% RTP should be inferred from the available information. A comparison of these inferred values with F_Q^{RTP} assures compliance with the LCO at all power levels.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by factors that account for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require power reductions within 15 minutes of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for

(continued)

BASES

ACTIONS

A.2 (continued)

protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux-High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux-High trip setpoints.

A.3

Reduction in the Overpower N-16 trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower N-16 trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower N-16 trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower N-16 trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum Overpower N-16 trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

(continued)

BASES

ACTIONS

A.4 (continued)

Inherent in this action is the identification of the cause of the out of limit condition and the correction of the cause, to the extent necessary to allow safe operation at the higher power level. The allowable power level is determined by extrapolating $F_Q^C(Z)$. SR 3.2.1.1.1 must be satisfied prior to increasing power above the extrapolated allowable power level or restoration of any reduced Reactor Trip System setpoints.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limits by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factor limits are not exceeded.

C.1

If Required Actions A.1 through A.4 or B.1 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1.1 and SR 3.2.1.1.2 are modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving Mode 1). The note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 20% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

$F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured for a reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 20%, ensures that they are verified within 24 hours from when equilibrium conditions are achieved at RTP (or any other level for extended operation). Equilibrium conditions are achieved when the core is sufficiently stable such that the uncertainty allowances associated with the measurement are valid. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 20% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 20% higher than that power at which F_Q was last measured.

<u>SR 3.2.1.1.1</u>

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z) \cdot 1.03 \cdot 1.05$ (Ref. 4). $F_Q^C(Z)$ is then compared to its specified limits.

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP, or at a reduced power level at any other time, and meeting the 100% RTP $F_Q(Z)$

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1.1 (continued)

limit, provides assurance that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 20% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 24 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

SR 3.2.1.1.2

Because flux maps are taken in equilibrium conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The limit with which $F_Q^W(Z)$ is compared varies inversely with power and directly with the function K(Z) provided in the COLR.

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 15% inclusive; and

b. Upper core region, from 85 to 100% inclusive.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1.2 (continued)

The top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. When $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^C(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression

maximum over z $\left[\frac{F_Q^C(Z)}{K(Z)}\right]$

it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by the appropriate factor of ≥ 1.02 specified in the COLR, or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP, or at a reduced power level at any other time, and meeting the 100% RTP $F_Q(Z)$ limit, provides assurance that the $F_Q(Z)$ limit will be met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 20% RTP above the THERMAL POWER of its last verification, 24 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.46, 1974.
2. Regulatory Guide 1.77, Rev. 0, May 1974.
3. 10 CFR 50, Appendix A, GDC 26.
4. RXE-90-006-P-A, "Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology," TU Electric, June 1994.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1.2 Heat Flux Hot Channel Factor ($F_Q(Z)$) (RAOC-W(Z) Methodology)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ 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 fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3.2, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT TILT POWER RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.7, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system or an OPERABLE PDMS. These measurements are generally taken with the core at or near equilibrium conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ that are present during non-equilibrium situations, such as load following. To account for these possible variations, the steady state value of $F_Q(Z)$ is adjusted by an elevation dependent factor, W(Z), that accounts for calculated worse case transient conditions.

Core monitoring and control under non-steady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

APPLICABLE SAFETY ANALYSES

This LCO's principal effect is to preclude core power distributions that could lead to violation of the following fuel design criterion:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1); and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm, and

c. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the LOCA peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of the 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \le \frac{F_Q^C}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{F_Q^C}{0.5} K(Z) \qquad \text{for } P \le 0.5$$

where:

F_Q^C is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

P = THERMAL POWER/RTP

The actual values of F_Q^C and K(Z) are given in the COLR.

(continued)

BASES

LCO (continued)

For Relaxed Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F_Q^C(Z)$ evaluation requires obtaining a core power distribution measurement in MODE 1. From the core power distribution measurement results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$.

If the PDMS is used, the appropriate measurement uncertainty and manufacturing allowance are automatically calculated and applied to the measured F_Q (Ref. 7).

If the movable incore detector system is used, the computed heat flux hot channel factor, $F_Q^C(Z)$, is obtained by the equation:

$$F_Q^C(Z) = F_Q^M(Z) \bullet 1.03 \bullet 1.05.$$

$F_Q^M(Z)$ is increased by 3% to account for manufacturing tolerances and further increased by 5% to account for measurement uncertainties.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z) \bullet W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients during normal operations. W(Z) is included in the COLR.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

(continued)

BASES

LCO (continued)

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q^C(Z)$ cannot be maintained within the LCO limits, a reduction of the core power is required and if $F_Q^W(Z)$ cannot be maintained within the LCO limits, reduction of the AFD limits is required. Note that sufficient reduction of the AFD limits will also result in a reduction of the core power.

Violating the LCO limits of $F_Q(Z)$ may produce unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by factors that account for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require power reductions within 15 minutes of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

(continued)

BASES

ACTIONS (continued)

A.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux-High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux-High trip setpoints.

A.3

Reduction in the Overpower N-16 trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower N-16 trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower N-16 trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower N-16 trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum Overpower N-16 trip setpoints.

(continued)

BASES

ACTIONS (continued)

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.2.1 and SR 3.2.1.2.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.2.1 and SR 3.2.1.2.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.2.1 and SR 3.2.1.2.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limits by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factor limits are not exceeded.

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints ≥ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reductions in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

(continued)

BASES

ACTIONS (continued)

B.3

Reduction in the Overpower N-16 setpoints value by $\geq$ 1% for each 1% by which the maximum allowable power is reduced, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reductions in THERMAL POWER as a result of reducing AFD limits in accordance with Required Action B.1.

B.4

Verification that $F_QW(Z)$ has been restored to within its limit by performing SR 3.2.1.2.1 and SR 3.2.1.2.2 prior to increasing THERMAL POWER above the maximum allowable power limit imposed by Required Action B.1 ensures that core conditions during operation at higher power levels and future operation are consistent with safety analysis assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.2.1 and SR 3.2.1.2.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition A is exited prior to performing Required Action B.4. Performance of SR 3.2.1.2.1 and SR 3.2.1.2.2 is necessary to ensure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2.1 and SR 3.2.1.2.2 are modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving Mode 1). The note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement can be obtained.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 20% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured for a reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 20%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 20% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 20% higher than that power at which F_Q was last measured.

SR 3.2.1.2.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. If the PDMS is used, the appropriate measurement uncertainty and manufacturing allowance are automatically calculated and applied to the measured F_Q (Ref. 7). If the movable incore detector system is used, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z) \cdot 1.03 \cdot 1.05$ (Ref. 4). $F_Q^C(Z)$ is then compared to its specified limits.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2.1 (continued)

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP, provides assurance that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 20% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 24 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

SR 3.2.1.2.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because power distribution measurements are taken at or near equilibrium conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the core power distribution measurement data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The limit with which $F_Q^W(Z)$ is compared varies inversely with power above 50% RTP and directly with the function K(Z) provided in the COLR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2.2 (continued)

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 15% inclusive; and

b. Upper core region, from 85 to 100% inclusive.

The top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. When $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^C(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression

maximum over z $\left[\frac{F_Q^C(Z)}{K(Z)}\right]$

it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by the appropriate factor of ≥ 1.02 specified in the COLR, or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP provides assurance that the $F_Q(Z)$ limit will be met when RTP is achieved because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 20% RTP above the THERMAL POWER of its last verification, 24 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2.2 (continued)

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

REFERENCES

1. 10 CFR 50.46, 1974.
2. Regulatory Guide 1.77, Rev. 0, May 1974.
3. 10 CFR 50, Appendix A, GDC 26.
4. RXE-90-006-P-A, "Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology," TU Electric, June 1994.
5. WCAP-7308-L-P-A, “Evaluation of Nuclear Hot Channel Factor Uncertainties,” June 1988.
6. WCAP-10216-P-A, Rev. 1A, “Relaxation of Constant Axial Offset Control (and) FQ Surveillance Technical Specification,” February 1994.
7. WCAP-12472-P-A, “BEACON Core Monitoring and Operations Support System,” August 1994.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during normal operation, operational transients, and any transient condition arising from events of moderate frequency analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod. $F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution measurement obtained with the movable incore detector system or an OPERABLE PDMS. Specifically, the results of the three dimensional power distribution measurement are analyzed to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables. Compliance with these LCOs, along with the LCOs governing shutdown and control rod insertion and alignment, maintains the core limits on power distribution on a continuous basis.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is

(continued)

BASES

BACKGROUND (continued)

no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. For ANS Condition II events, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F;

c. During an ejected rod accident, the average fuel pellet enthalpy at the hot spot must not exceed 280 cal/gm (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion applicable to a specific DNBR correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB condition.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LOCA safety analysis also uses $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

The fuel is protected in part by compliance with Technical Specifications which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.7, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system or an OPERABLE PDMS. Measurements are generally taken with the core at, or near, equilibrium conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit is representative of the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB condition.

The limiting value of $F^N_{\Delta H}$ described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional allowance for higher radial peaking factors from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase by a cycle-dependent factor ($PF_{\Delta H}$, as specified

(continued)

BASES

LCO (continued)

in the COLR) for a 1% RTP reduction in THERMAL POWER.

If the power distribution measurements are performed at a power level less than 100% RTP, then the $F^N{}_{\Delta H}$ values that would result from measurements if the core was at 100% RTP should be inferred from the available information. A comparison of these inferred values with $F_{\Delta H}{}^{RTP}$ assures compliance with the LCO at all power levels.

APPLICABILITY

The $F^N{}_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time. The restoration of the peaking factor to within its limits by power reduction or control rod movement does not restore compliance with the LCO. Thus, this condition can not be exited until a valid surveillance demonstrates compliance with the LCO.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, even if this Required Action is completed within the 4 hour time period, Required

(continued)

BASES

ACTIONS

A.1.1 (continued)

Action A.2 requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP; however, THERMAL POWER does not have to be reduced to comply with these requirements. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux-High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing power to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints; however, for extended operations at the reduced power level, the reduced trip setpoints are required to protect against events involving positive reactivity excursions. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once actions have been taken to restore $F^N_{\Delta H}$ to within its limits per

(continued)

BASES

ACTIONS

A.2 (continued)

Required Action A.1.1, or the power level has been reduced to < 50% RTP per Required Action A.1.2.1, a core power distribution measurement (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period.

Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the core power distribution measurement, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is identified, to the extent necessary, and corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP. SR 3.2.2.1 must be satisfied prior to increasing power above the extrapolated allowable power level or restoration of any reduced Reactor Trip System setpoints. When $F^N_{\Delta H}$ is measured at reduced power levels, the allowable power level is determined by evaluating $F^N_{\Delta H}$ for higher power levels.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at

(continued)

BASES

ACTIONS

B.1 (continued)

least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

SR 3.2.2.1 is modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving Mode 1). The note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement can be obtained. Equilibrium conditions are achieved when the core is sufficiently stable such that the uncertainty allowances associated with the measurement are valid.

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system or an OPERABLE PDMS to obtain a power distribution measurement. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. If the PDMS is used, the appropriate measurement uncertainty is automatically calculated and applied to the measured $F^N_{\Delta H}$ (Ref. 4).

If the moveable incore detector system is used the measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle. Performing this Surveillance in MODE 1 prior to exceeding 75% RTP, or at a reduced power level at any other time, and meeting the 100% RTP $F^N_{\Delta H}$ limit, provides assurance that the $F^N_{\Delta H}$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 (continued)

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

REFERENCES

1. Regulatory Guide 1.77, Rev. 0, May 1974.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46.
4. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3.1 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The operating scheme used to control the axial power distribution, CAOC, involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during unit maneuvers.

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position (i.e., ≥ 180 steps withdrawn) for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the Fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The frequency of monitoring the AFD by the unit computer is once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to accurately assess the status of the penalty deviation time. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message if the AFDs for two or more OPERABLE excore channels are outside the target band and the THERMAL POWER is > 90% RTP. During operation at THERMAL POWER levels < 90% RTP but ≥ 15% RTP, the computer sends an alarm message when the cumulative penalty deviation time is > 1 hour in the previous 24 hours.

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BASES (continued)

APPLICABLE SAFEY ANALYSES

The Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) and QPTR LCOs limit the radial component of the peaking factors. The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The CAOC methodology (Refs. 1, 2, and 3) entails:

a. Establishing an envelope of allowed power shapes and power densities;

b. Devising an operating strategy for the cycle that maximizes unit flexibility (maneuvering) and minimizes axial power shape changes;

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics; and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition II, III, and IV events. Compliance with this limit ensures that acceptable levels of fuel cladding integrity is maintained for these postulated accidents. The most important Condition IV event is the loss of coolant accident. The most significant Condition III event is the complete loss of forced RCS flow accident. The most significant Condition II events are uncontrolled bank withdrawal and boration or dilution accidents. Condition II accidents are used to confirm the adequacy of Overpower N-16 and Overtemperature N-16 trip setpoints.

The limits on the AFD satisfy Criterion 2 of the 10CFR50.36(c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to

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BASES

LCO (continued)

temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 4). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

This LCO is modified by a Note that states the conditions necessary for declaring the AFD outside of the target band. The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup.

With THERMAL POWER ≥ 90% RTP, the AFD must be kept within the target band. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated.

Parts B and C of this LCO are affected by Notes that describe how the cumulative penalty deviation time is calculated. It is intended that the unit is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part B of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours, is allowed during which the unit may be operated outside of the target band but within the acceptable operation limits provided in the COLR. This penalty time is accumulated at the rate of 1 minute for each 1 minute of operating time within the power range of Part B of this LCO (i.e., THERMAL POWER ≥ 50% RTP). The cumulative penalty time is the sum of penalty times from Parts B and C of this LCO.

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part C of

(continued)

BASES

LCO (continued)

this LCO), deviations of the AFD outside of the target band are less significant. The accumulation of 1/2 minute penalty deviation time per 1 minute of actual time outside the target band reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distributions are prevented by limiting the accumulated penalty deviation time.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

APPLICABILITY

AFD requirements are applicable in MODE 1 above 15% RTP. Above 50% RTP, the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1).

Between 15% RTP and 90% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. The value of the AFD in these conditions does not affect the consequences of the design basis events.

For surveillance of the power range channels performed according to SR 3.3.1.6, deviation outside the target band is permitted for 16 hours and no penalty deviation time is accumulated. Some deviation in the AFD may be required for the performance of the NIS calibration with the incore detector system. This calibration is typically performed every 92 days.

Low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

ACTIONS

A.1

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

(continued)

BASES

ACTIONS (continued)

B.1

If the AFD cannot be restored within the target band, then reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes provides an acceptable time to reduce power to < 90% RTP without allowing the plant to remain in an unanalyzed condition for an extended period of time.

C.1

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band but within the acceptable operation limits provided in the COLR provided in the COLR is allowed for up to 1 hour. With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. The reduction to a power level < 50% RTP puts the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. (Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits.) The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

Condition C is modified by a Note that requires that Required Action C.1 must be completed whenever this Condition is entered.

D.1

If Required Action C.1 is not completed within its required Completion Time of 30 minutes, the axial xenon distribution starts to become significantly skewed with the THERMAL POWER ≥ 50% RTP. In this situation, the assumption that a cumulative penalty deviation time of 1 hour or less during the previous 24 hours while the AFD is outside its target band is acceptable at < 50% RTP, is no longer valid.

(continued)

BASES

ACTIONS

D.1 (continued)

Reducing the power level to < 15% RTP within the Completion Time of 9 hours and complying with LCO penalty deviation time requirements for subsequent increases in THERMAL POWER ensure that acceptable xenon conditions are restored.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1.1

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band. The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed.

SR 3.2.3.1.2

Not Used.

SR 3.2.3.1.3

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

The target AFD must be determined in conjunction with the measurement of $F_Q^W(Z)$; therefore, the frequency for the performance of this surveillance is the same as that required for the performance of the $F_Q^W(Z)$ surveillance per SR 3.2.1.1.2.

A Note modifies this SR to allow the predicted beginning of cycle AFD from the Startup and Operations Report to be used to determine the initial target flux difference after each refueling. This note allows operation until the power level for extended operations has been achieved and an equilibrium power distribution can be obtained.

REFERENCES

1. RXE-90-006-P-A,"Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology," TU Electric, June, 1994.

(continued)

BASES

REFERENCES (continued)

2. WCAP-8385 (W proprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

3. T. M. Anderson to K. Kniel (Chief of Core Performance Branch, NRC), Attachment: "Operation and Safety Analysis Aspects of an Improved Load Follow Package," January 31, 1980.

4. FSAR, Chapter 7.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3.2 AXIAL FLUX DIFFERENCE (AFD) (Relaxed Axial Offset Control (RAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

RAOC is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the transient limits are met. Violation of the AFD limits invalidates the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

AFD is monitored on an automatic basis using the Unit process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

Although the RAOC defines limits that must be met to satisfy safety analyses, typically an operating scheme such as Constant Axial Offset Control (CAOC) is used to control axial power distribution in day to day operation (Ref. 2). CAOC requries that the AFD be controlled within a narrow tolerance band around a burnup dependent target to minimize the variation of axial peaking factors and axial xenon distribution during Unit maneuvers.

The CAOC operating space is typically smaller and lies within the RAOC operating space. Control within the CAOC operating space constrains the variation of axial xenon distributions and axial power distributions. RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

(continued)

BASES (continued)

APPLICABLE SAFEY ANALYSES

The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temeprature and boron concentration.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The RAOC methodology (Ref. 5) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the loss of coolant accident and loss of lfow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition II, III, and IV events. Compliance with this limit ensures that acceptable levels of fuel cladding integrity is maintained for these postulated accidents. The most important Condition IV event is the loss of coolant accident. The most significant Condition III event is the complete loss of forced RCS flow accident. The most significant Condition II events are uncontrolled bank withdrawal and boration or dilution accidents. Condition II accidents are used to confirm the adequacy of Overpower N-16 and Overtemperature N-16 trip setpoints.

The limits on the AFD satisfy Criterion 2 of the 10CFR50.36(c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 4). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each

(continued)

BASES

LCO (continued)

detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

The AFD limits are provided in the COLR. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

APPLICABILITY

The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP, when the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1).

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

ACTIONS

A.1

As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.2.1

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within its specified limits. The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from requirements that is not alarmed should be readily noticed.

(continued)

BASES (continued)

REFERENCES

1. RXE-90-006-P-A,"Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology," TU Electric, June, 1994.

2. WCAP-8385 (W proprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

3. T. M. Anderson to K. Kniel (Chief of Core Performance Branch, NRC), Attachment: "Operation and Safety Analysis Aspects of an Improved Load Follow Package," January 31, 1980.

4. FSAR, Chapter 7.

5. WCAP-10216-P-A, Rev. 1A, “Relaxation of Constant Axial Offset Control (and) F_Q Surveillance Technical Specification,” February 1994.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.7, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

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

a. During a large break loss of coolant accident, 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 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the average fuel pellet enthalpy at the hot spot must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, above which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and ($F^N_{\Delta H}$) is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition. The maximum allowable THERMAL POWER level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require a THERMAL POWER reduction within 2 hours of QPTR determination, if necessary to comply with the decreased maximum

(continued)

BASES

ACTIONS

A.1 (continued)

allowable THERMAL POWER level. Decreases in QPTR would allow raising the maximum allowable THERMAL POWER level and increasing THERMAL POWER up to this revised limit.

A.2

After completion of Required Action A.1, the QPTR may still exceed its limits. Any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F^N_{\Delta H}$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions to support core power distribution measurements. A Completion Time of 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform core power distribution measurements. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction

(continued)

BASES

ACTIONS

A.4 (continued)

accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This evaluation is required to ensure that, before increasing THERMAL POWER to above the limits of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR remains above the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limit prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the excore detectors are not normalized to restore to restore QPTR to within limits until after the evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limit, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing core power distribution measurements to verify peaking factors per Required Action A.6. These notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the excore detectors are normalized to restore QPTR to within limit (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at

(continued)

BASES

ACTIONS

A.6 (continued)

RTP within 24 hours but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. This Completion Time is intended to allow adequate time to increase THERMAL POWER to above the limits of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances must be completed when the excore detectors have been normalized to restore QPTR to within limit (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limit.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days takes into account other information and alarms available to the operator in the control room.

For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the inputs from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for ensuring that any tilt remains within its limits.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors or an OPERABLE PDMS may be used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. When using the moveable incore detector system, the incore detector monitoring is performed with a full incore flux map or two sets of four thimble locations with quarter core symmetry. The two sets of four symmetric thimbles is a set of eight unique detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, and N-8.

The symmetric thimble flux map can be used to generate symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore monitoring of QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous core power distribution measurements using an OPERABLE PDMS and the symmetric thimbles as described above or a complete flux map. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

REFERENCES

1. 10 CFR 50.46.

2. Regulatory Guide 1.77, Rev 0, May 1974.

3. 10 CFR 50, Appendix A, GDC 26.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

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

For the purposes of demonstrating compliance with 10CFR50.36, the Technical Specifications must specify Limiting Safety System Settings (LSSS). The Allowable Value specified in Table 3.3.1-1 serves as the LSSS except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Funcitons). The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

The Allowable Value serves as the LSSS except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safty system setting for these Trip Functions) such that a channel is OPERABLE if the as found trip setpont value does not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the established trip setpoint calibration tolerance band in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the allowances of the uncertainty terms assigned.

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

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the departure from nucleate boiling ratio (DNBR) limit;

2. Fuel centerline melt shall not occur; and

3. The RCS pressure Safety Limit of 2735 psig shall not be exceeded.

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BASES

BACKGROUND (continued)

Operation within the limits of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs. Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is segmented into four distinct but interconnected modules as described in the FSAR, Chapter 7 (Ref. 1), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System, including the 7300 Process Instrumentation and Control System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/ miscellaneous indications or alarms;

3. Solid State Protection System (SSPS), including input, logic, and output bays: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument

(continued)

BASES

BACKGROUND (continued)

drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy.

The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 3). The actual number of channels required for each unit parameter is specified in Reference 1.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that

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BASES

BACKGROUND (continued)

testing required while the reactor is at power may be accomplished without initiating protective action, unless a trip condition actually exists. This arises from the use of coincidence logic in generating reactor trip signals and from the capability to bypass a partial protective action while in test.

Allowable Values and Trip Setpoints

The trip setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. The essential elements of the methodology for all Trip Functions 2a, 2b, 6, 7, and 14 are described in Reference 9. Changes in accordance with this methodology have been reviewed by the staff in the original Unit 2 Technical Specifications and in several subsequent license amendments (e.g., amendments 21/7 and 22/8 to the Unit 1/Unit 2 Technical Specifications). The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE. The trip setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The trip setpoint value ensures the LSSS and the safety analysis limits are met for the time period of the surveillance interval when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the “as left” setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The trip setpoint value of Table B3.3-1.1 is therefore considered a “nominal” value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION for all Trip Functions 2a, 2b, 6, 7, and 14.

The methodology used to calculate the Nominal Trip Setpoints 2a, 2b, 6, 7, and 14 in Table B 3.3.1-1 is the same basic square-root-sum-of-squares (SRSS) methodology with the inclusion of refinements to better reflect plant

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BASES

BACKGROUND (continued)

calibration practices and equipment performance. The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Trip setpoints consistent with the requirements of the Allowable Value ensure that design limits are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions).

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

The Allowable Values listed in Table 3.3.1-1, except for Functions 2a, 2b, 6, 7, and 14 incorporates all of the known uncertainties applicable for each channel. The Allowable Values for Functions 2a, 2b, 6, 7, and 14 are based on the Nominal Trip Setpoints and are determined by subtracting or adding the rack calibration accuracy from the Nominal Trip Setpoint. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

(continued)

BASES

BACKGROUND (continued)

The SSPS performs the decision logic for actuating a reactor or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the SSPS is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the SSPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each reactor trip breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the SSPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

The decision logic matrix Functions are described in the functional diagrams included in Reference 1. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the decision logic matrix Functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the applicable Safety Limits during all AOOs and mitigates the consequences of DBAs in all MODES in which the Rod Control system is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 2 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backup or diverse trips to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band provided the trip setpoint “as-found” value does not exceed its associated Allowable Value and provided the trip setpoint “as-left” value is adjusted to a value within the calibration tolerance band of the Nominal Trip Setpoint except for Trip Functions 2a, 2b, 6, 7, and 14. Note (r) requires the instrument channel setpoint for a channel in these Trip Functions to be reset to a value that is within the as-left setpoint tolerance of the Nominal Trip Setpoint. The conservative direction is indicated by the direction of the inequality sign applied to the Nominal Trip Setpoint in Bases Table B 3.3.1-1. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisifed in order to protect the safety analysis limits. Note (r) preserves the safety analysis limits. If the channel can not be reset to a value within its as-left setpoint tolerance band, or to a value that is more conservative than the Nominal Trip Setpoint if required based on plant conditions, the channel shall be declared inopreable and the applicable Required Actions are taken. The methodology used to determine the as-left setpoint tolerance band is based on the square-root-sum-of-squares (SRSS) of the tolerances applicable to the instrument loop or sub-loop constituents being tested. The applicability of notes (q) and (r) for Unit 1, items 2a, 2b, 6, and 7 will begin following the completion of Cycle 13. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection, even with a random failure of one of the other three protection channels. Three operable instrumentation channels in a two-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped or bypassed during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core.

In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if one or more shutdown or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core and all the rods are fully inserted, there is no need to be able to trip the reactor, because all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux-High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux-High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux-High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could result in an unacceptable level of damage to the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux-High does not have

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. <u>Power Range Neutron Flux-Low</u>

The LCO requirement for the Power Range Neutron Flux-Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux-Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux-Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux-High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. <u>Power Neutron Flux Rate-High Positive Rate</u>

The Power Range Neutron Flux Rate trips use the same channels as discussed for Function 2 above.

The Power Range Neutron Flux-High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the accompanying ejection of the RCCA. This Function complements the Power Range Neutron Flux-High and Low Setpoint trip Functions to ensure that the criteria are met for a rod ejection from the power range.

The LCO requires all four of the Power Range Neutron Flux-High Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the Power Range Neutron Flux-High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions or administrative controls will provide protection against inadvertent positive reactivity additions. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this mode.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux-Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing (generally performed at power levels greater than the P-10 setpoint or less than

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the P-6 setpoint) while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux - High Setpoint trip and the Power Range Neutron Flux - High Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 2 below the P-6 setpoint, the Source Range Neutron Flux trip Function provides core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux-Low and Intermediate Range Neutron Flux trip Functions. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5 with the Rod Control System capable of rod withdrawal or with one or more rods not fully inserted. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The outputs of the Function to RTS logic are not required OPERABLE in Mode 6 or when all rods are fully inserted and the Rod Control System is incapable of rod withdrawal.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical and control rod ejection events.

In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux-Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors may be manually blocked. After the source range trip function is blocked, the high voltage power supply is removed.

In MODES 3, 4, and 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted, the Source Range Neutron Flux trip Function must also be OPERABLE. If the Rod Control System is capable of rod withdrawal, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal accident. If the Rod Control System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. However, it is good practice for their monitoring Function to be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like an inadvertent boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.3, "Nuclear Instrumentation."

6. <u>Overtemperature N-16</u>

The Overtemperature N-16 trip Function is provided to ensure that the design limit DNBR is met. The inputs to the Overtemperature N-16 trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop N-16 power monitors, assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system.

The Overtemperature N-16 trip Function uses each loop's N-16 power indication as a measure of reactor power and compares the compensated N-16 measured power with a setpoint that is automatically varied with the following parameters:

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- reactor coolant cold leg temperature-the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure-the Trip Setpoint is varied to correct for changes in system pressure; and

- axial power distribution-f(Δq), the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limits, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the N-16 power and temperature measurement systems.

The Overtemperature N-16 power allowable value is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if the loop-specific Overtemperature N-16 setpoint is exceeded in two of the four RCS loops. The N-16 power, pressurizer pressure and cold leg temperature signals are used for other control functions; thus, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature N-16 condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature N-16 trip Function to be OPERABLE. Note that the Overtemperature N-16 Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature N-16 trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower N-16

The Overpower N-16 trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature N-16 trip Function and provides a backup to the Power Range Neutron Flux-High Setpoint trip. This is because Overpower N-16 is not sensitive to changes in the density of the reactor vessel downcomer fluid and additionally, the overpower function is credited in the analyses of the decrease in feedwater temperature event and for some steamline break accidents.

The Overpower N-16 trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the N-16 power monitor indication of each loop as a measure of reactor power with a constant value setpoint.

The Overpower N-16 power indication is calculated for each RCS loop. Trip occurs if the N-16 power exceeds the setpoint in any two loops. The actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower N-16 condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower N-16 trip Function to be OPERABLE. Note that the Overpower N-16 trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower N-16 trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure-High and -Low trips and the Overtemperature N-16 trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System; thus, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels of Pressurizer Pressure-Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure-Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine impulse pressure greater than approximately 10% of full power equivalent (P-13)). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, there is insufficient heat production to be concerned about DNB.

b. Pressurizer Pressure-High

The Pressurizer Pressure-High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires four channels of the Pressurizer Pressure-High to be OPERABLE.

The Pressurizer Pressure-High Allowable Value is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure-High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure-High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when in MODE 4 or below.

9. <u>Pressurizer Water Level-High</u>

The Pressurizer Water Level-High trip Function provides a backup signal for the Pressurizer Pressure-High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level-High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/ protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting.

Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level-High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Coolant Flow-Low

The Reactor Coolant Flow-Low trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any RCS loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

Following plant heatup from a refueling outage, the RCS flow transmitters are adjusted (normalized) with the reactor coolant pumps in service to indicate 100% flow (nominal). During the subsequent plant startup, the RCS flow is measured in accordance with SR 3.4.1.4 to confirm that the actual flow is greater than the value assumed in the accident analysis. At this time, it is also verified that the RCS flow instruments continue to indicate 100% flow (within established tolerances). If not, the flow transmitters are readjusted (normalized) to indicate 100% flow (nominal). The value for the RCS low flow setpoint, expressed as a percentage of indicated flow, is periodically verified to be within required tolerances in accordance with SR 3.3.1.7 and SR 3.3.1.10. This process ensures that the nominal setpoint is consistent with the assumptions of the accident analysis.

The LCO requires three Reactor Coolant Flow-Low channels per loop to be OPERABLE in MODE 1 above P-7.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core because of the higher power level. In MODE 1 below the P-8 setpoint and above the P-7 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (because of the lower power level and the greater margin to the design limit DNBR. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow-Low (Two Loops) trip must be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to be concerned about DNB.

11. Not Used.

12. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires four Undervoltage RCP channels (one per RCP) to be OPERABLE. The required channels are stated as one per bus because each bus has only one RCP.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since the core is not producing sufficient power to generate DNB conditions. Above the P-7 setpoint, the reactor trip on Undervoltage - RCPs is automatically enabled.

13. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. An adequate coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low Trip Setpoint is reached. Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires four Underfrequency RCPs channels (1 per RCP) to be OPERABLE. The required channels are stated as one per bus because each bus has only one RCP.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since the core is not producing sufficient power to generate DNB conditions. Above the P-7 setpoint, the reactor trip on underfrequency is automatically enabled.

14. Steam Generator Water Level-Low Low

The SG Water Level-Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low water level signal in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires four channels of SG Water Level-Low Low per SG to be OPERABLE because these channels are shared between protection and control. The actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level. The LCO requires four channels of SG Water Level-Low Low per SG to be OPERABLE.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level-Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2 above the point of adding heat. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4, 5, or 6, the SG Water Level-Low Low reactor trip function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6. Because this Function also performs an ESFAS Function a note is added to indicate that ESFAS APPLICABILITY is more restrictive.

15. Not Used.

16. Turbine Trip

a. Turbine Trip-Low Fluid Oil Pressure

The Turbine Trip-Low Fluid Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint of 50% power will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip-Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip-Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip-Turbine Stop Valve Closure

The Turbine Trip-Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

secondary system following a turbine trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. A turbine trip from a power level below the P-9 setpoint will not actuate a reactor trip. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip-Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If all four limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

The Allowable Value for this Function is set to assure channel trip occurs when the associated stop valve is completely closed.

The LCO requires four Turbine Trip-Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. All four channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump and Rod Control Systems. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip-Stop Valve Closure trip Function does not need to be OPERABLE.

17. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any automatic signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by logic in the SSPS circuitry of the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

18. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip; and

- on increasing power, the P-6 interlock provides a backup block signal to the source range flux doubling circuit. Note that this function is not required for operability of the source range detectors. Normally, this Function is manually blocked by the control room operator during the reactor startup.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary. In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

b. <u>Low Power Reactor Trips Block, P-7</u>

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure, P-13 interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (low flow in two or more RCS loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (low flow in two or more RCS loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

Allowable Values are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 48% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow-Low reactor trip on low

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than 48% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors. The LCO requirement for this Function ensures that the Turbine Trip-Low Fluid Oil Pressure and Turbine Trip-Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacities of the Steam Dump and Rod Control Systems. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.

In MODE 1, above P-9, a turbine trip could cause a load rejection beyond the capacities of the Steam Dump and Reactor Control Systems, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacities of the Steam Dump and Rod Control Systems.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux-Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux-Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

P-10 has two allowable values; one allowable value is associated with increasing power levels and the second allowable value is associated with decreasing power levels,

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux-Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

f. The Turbine First Stage Pressure, P-13

The Turbine First Stage Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the full power pressure. The full power pressure corresponds to the first stage pressure at 100% RTP. The interlock is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine First Stage Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine First Stage Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

19. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the CRD System. Thus, the train may consist of the main breaker or the main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 19 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

21. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 19 and 20) and Automatic Trip Logic (Function 21) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs and associated bypass breakers are closed, and the the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(2)(c)(ii).

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BASES (continued)

ACTIONS

A Note has been 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 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the Required Channels in Table 3.3.1-1 are specified on a per loop, per SG, per bus, per train or per RTB basis, then the Condition may be entered separately for each loop, SG, bus, train or RTB, as appropriate. When a single LCO addresses multiple Functions and allows separate Condition entry for each function, each Function is identified by a unique number/letter. A single Function may contain different requirements for different Applicabilities. In such cases, initial inoperability of a channel or train is based upon the Function independent of the applicability. For example, if a Function has one set of requirements for Modes 1 and 2 and a second set of requirements for Modes 3, 4 and 5, the same channel inoperability may result in entering separate Conditions at different times. If initially inoperability occurs in Modes 1 or 2, the Conditions for Modes 1 and 2 are entered. Completion times must be met unless the Condition is exited by restoring the inoperable channel to OPERABLE or by entry into Mode 3. A note must so specify if any Required Action must be completed after a Condition is no longer applicable. Upon entry into Mode 3, the Conditions for Modes 3, 4, and 5 must be entered and completions times start upon entry into the Condition. If a Completion Time starts with initial inoperability of the channel, a note is required to so specify.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, 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 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 are reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, Condition C is entered if the Manual Reactor trip function has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

C.1, C.2.1 and C.2.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour

(continued)

BASES

ACTIONS

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

Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to fully insert all rods and the Rod Control System be rendered incapable of rod withdrawal within the next hour (e.g., by de-energizing all CRDMs, by opening the RTBs, or de-energizing the motor generator (MG) sets). The additional hour provides sufficient time to accomplish the action in an orderly manner. In this condition, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

Condition C is modified by a Note stating that while the LCO is not met in MODE 5 making the Rod Control System capable of rod withdrawal is not permitted for Functions 19, 20, or 21. This Note specifies an exception to LCO 3.0.4 and avoids placing the plant in a condition where control rods can be withdrawn while the reactor trip system is degraded.

D.1.1, D.1.2, and D.2

Condition D applies to the Power Range Neutron Flux-High Function.

With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost. Therefore, SR 3.2.4.2 must be performed (Required Action D.1.1) within 12 hours of THERMAL POWER exceeding 75% RTP and once per 12 hours thereafter. If reactor power decreases to ≤ 75% RTP, the measurement of both Completion Times for Required Action D.1.1 stops and SR 3.2.4.2 is no longer required. Completion Time tracking recommences upon reactor power exceeding 75% RTP. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued plant operation at power levels > 75% RTP. At power levels ≤ 75% RTP, operation of the core with radial power distributions beyond the design limits, at a power level where DNB conditions may exist, is prevented. The 12 hour Completion Time is consistent with the SR 3.2.4.2 Frequency in LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR).”

Required Action D.1.1 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not

(continued)

BASES

ACTIONS

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

affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors or an OPERABLE PDMS once per 12 hours may not be necessary.

The NIS power range detectors provide input to the CRD System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-14333-P-A (Ref. 11).

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight (78) hours are allowed to place the plant in MODE 3. The 78-hour Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction as required by Required Action D.2. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions are modified by a Note that allows placing one channel in bypass for 12 hours while performing routine surveillance testing, and setpoint adjustments when a setpoint reduction is required by other Technical Specifications. The 12 hour time limit is justified in Reference 11.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux-Low;
- Overtemperature N-16;
- Overpower N-16;
- Power Range Neutron Flux-High Positive Rate;
- Pressurizer Pressure-High; and
- SG Water Level-Low Low.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 11.

If the operable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in References 8 and 11.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, the overlap of the Power Range detectors, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This action will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. This action may require the use of the NIS source range channels or the neutron flux channels discussed in LCO 3.3.3, with action to reduce power below the count rate equivalent to the P-6 setpoint.

Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

Required Action G.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron concentration fluctuations associated with RCS inventory or chemistry management or temperature control) are not precluded by this Action, provided the SDM limits specified in the COLR are met and the requirements of LCOs 3.1.5, 3.1.6, and 3.4.2 are met.

H.1

Not Used.

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

(continued)

BASES

ACTIONS

I.1 (continued)

This action will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action I.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron concentration fluctuations associated with RCS inventory or chemistry management or temperature control) are not precluded by this Action, provided the SDM limits specified in the COLR are met, the requirements of LCOs 3.1.5, 3.1.6, and 3.4.2 are met, and the initial and critical boron concentration assumptions in FSAR Section 15 are satisfied.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, or in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

K.1, K.2.1 and K.2.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, action must be initiated within the same 48 hours to fully insert all rods. 1 additional hour is allowed to fully insert all rods and place the Rod Control System in a condition incapable of rod withdrawal (e.g., by de-energizing all CRDMs, by opening the RTBs, or de-energizing the motor generator (MG) sets). Once these ACTIONS are completed, the core is in a more stable condition. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to place the Rod Control System in a condition incapable of rod withdrawal, are reasonable considering the other source range channel remains OPERABLE to perform the safety function and given the low probability of an event occurring during this interval. Normal plant control operations that individually add limited positive

(continued)

BASES

ACTIONS

K.1, K.2.1 and K.2.2 (continued)

reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory or chemistry management or temperature control) are permitted provided the ADM limits specified in the COLR are met and the initial and critical boron concentration assumptions in FSAR Section 15 are satisfied.

L.1

Not Used.

M.1 and M.2

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low;
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For the Pressurizer Pressure-Low, Pressurizer Water Level-High, Undervotage RCPs, and Underfrequency RCPs trip Functions, placing the channel in the tripped condition when above the P-7 setpoint results in a partial trip condition requiring only one additional channel to initiate a reactor trip. For the Reactor Coolant Flow - Low trip Function, placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. Two tripped channels in two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 11. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

(continued)

BASES

ACTIONS

M.1 and M.2 (continued)

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition M.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in References 8 and 11.

N.1

Not Used.

O.1 and O.2

Condition O applies to Turbine Trip on Low Fluid Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 11.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 11.

P.1 and P.2

Condition P applies to Turbine Trip on Turbine Stop Valve Closure. With one or more channels inoperable, the inoperable channel(s) must be placed in the trip condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition. For the Turbine Trip on Turbine Stop Valve Closure function, four of four channels are required to initiate a reactor trip; hence, more than one channel may be placed in trip. If the channels cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channels in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 11.

(continued)

BASES

ACTIONS (continued)

Q.1 and Q.2

Condition Q applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status (Required Action Q.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action Q.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable train to OPERABLE status is justified in Reference 11. The Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

Consistent with the requirement in Reference 11 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions do not apply when a logic train is being tested under the 4-hour bypass Note of Condition Q). Entry into Condition Q is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition Q is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition Q entry. If this situation were to occur during the 24-hour Completion Time of Required Action Q.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition Q or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

(continued)

BASES

ACTIONS

Q.1 and Q.2 (continued)

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 12. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in Condition C entry if one RTB train is inoperable.

The Required Actions have been modified by a Note. The Note allows one channel to be bypassed for up to 4 hours for surveillance testing or maintenance provided the other channel is OPERABLE. The 4 hour time limit is justified in reference 11.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a RTB train is inoperable for maintenance are included (note that these restrictions do not apply when a RTB train is being tested under the 4-hour bypass Note for TS 3.3.1 Condition R). Entry into Condition R is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition R is typically entered due to equipment failure, it follows that some of the following Tier 2 restrictions may not be met at the time of Condition R

(continued)

BASES

ACTIONS

R.1 and R.2 (continued)

entry. If this situation were to occur during the 24-hour Completion Time of Required Action R.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable RTB train and exit Condition R or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be put in place:

- The probability of failing to trip the reactor on demand will increase when a RTB is removed from service, therefore, systems designed for mitigating an ATWS event should be maintained available. RCS pressure relief (pressurizer PORVs and safeties), auxiliary feedwater flow (for RCS heat removal), AMSAC, and turbine trip are important to alternate ATWS mitigation. Therefore, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should be scheduled when a RTB train is inoperable for maintenance.

- Due to the increased dependence on the available reactor trip train when one logic train or one RTB train is inoperable for maintenance, activities that degrade other components of the RTS, including master relays or slave relays, and activities that cause analog channels to be unavailable, should not be scheduled when a logic train or RTB is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first two bullets should not be scheduled when a RTB train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one or more required channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually, e.g., by observation of the permissive annunciator window, accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for

(continued)

BASES

ACTIONS

S.1 and S.2 (continued)

manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

T.1 and T.2

Condition T applies to the P-7, P-8, P-9, and P-13 interlocks. With one or more channel(s) inoperable, the associated interlock must be verified to be in its required state for the existing unit condition by observation of the permissive annunciator window within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

U.1 and U.2

Condition U applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

With the unit in MODE 3, Condition C is entered if the Reactor Trip Breaker trip mechanism has not been restored and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features as described in Condition R.

The Completion Time of 48 hours for Required Action U.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

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

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

The Frequency is based on 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 the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS and N-16 power indications every 24 hours. If the calorimetric exceeds the NIS or N-16 power indications by more than +2% RTP, the affected NIS and N-16 functions are not declared inoperable, but the channel gains must be adjusted consistent with the calorimetric power. If the NIS or N-16 channel outputs cannot be properly adjusted, the channel is declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

If the NIS and N-16 power indications are normalized to within 2% RTP of the calorimetric power, and reactor power is then reduced, the NIS power indication will be lower than actual due to downcomer temperature shielding and neutron flux redistribution effects. The N-16 power indication will not be influenced by these effects. If a calorimetric measurement is then performed, using the Leading Edge Flow Meter (LEFM) to determine the feedwater flow, the NIS power indication may be normalized to the calorimetric power. Upon a subsequent return to near full power, the NIS power indication may become higher than actual due to the same downcomer temperature shielding and neutron flux redistribution effects. Again, the N-16 power indication will not be influenced by these effects.

The uncertainty associated with the calorimetric power measurement using the LEFM is independent of the reactor power level down to less than 20% RTP. However, if the LEFM is unavailable, and the calorimetric power measurement is performed using the feedwater venturis as the source of the feedwater flow information, additional considerations are required.

If the venturi-based calorimetric is performed at reduced power (<55% RTP), adjusting the Power Range indication in the increasing power direction will assure a reactor trip below the safety analysis limit. Making no adjustment to the Power Range channel in the decreasing power direction due to a reduced power venturi-based calorimetric assures a reactor trip consistent with the safety analyses. Based on plant calculations, 55% RTP is the lowest power at which the calorimetric uncertainty, performed with the feedwater venturis and the precision set of transmitters, results in an uncertainty of less than 2%.

This allowance does not preclude making indicated power adjustments, if desired, when the venturi-based calorimetric heat balance calculation is less than the NIS or N-16 channel outputs. To provide close agreement between indicated power and to preserve operating margin, the NIS and N-16 power indications are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the NIS or N-16 power indications are adjusted in the decreasing power direction based on a reduced power venturi-based calorimetric (<55% RTP). This action may introduce a non-conservative bias at higher power levels which may result in a reactor trip above the safety analysis limit. The most significant cause of the potential non-conservative bias is the decreased accuracy of the venturi-based calorimetric measurement at reduced power conditions. The primary error contributor to the instrument uncertainty for a secondary side venturi-based power calorimetric measurement is the feedwater flow measurement, which is a differential pressure (ΔP) measurement across a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

feedwater venturi. While the measurement uncertainty remains constant in ΔP as power decreases, when translated into flow, the uncertainty increases as a square term. Thus, a 1% flow error at 100% power can approach a 10% flow error at 30% RTP event though the ΔP error has not changed.

An evaluation of extended operations at reduced power conditions would likely conclude that it is prudent to administratively adjust the setpoint of the Power Range Neutron Flux - High bistables to ≤ 90% RTP when: 1) the Power Range channel output is adjusted in the decreasing power direction due to a reduced power venturi-based calorimetric below 55% RTP; or 2) for a post refueling startup (consistent with the Bases for SR 3.4.1.4). The evaluation of extended operation at reduced power conditions would also likely conclude that the potential need to adjust the indication of the Power Range Neutron Flux in the decreasing power direction is quite small, primarily to address operation in the intermediate range about P-10 (nominally 10% RTP) to allow enabling of the Power Range Neutron Flux - Low setpoint and the Intermediate Range Neutron Flux reactor trips. Before the Power Range Neutron Flux - High bistables are reset to their nominal value high setpoint, the NIS or N-16 power indication adjustment must be confirmed based on LEFM-based calorimetric or on a venturi-based calorimetric performed at ≥ 55% RTP.

The Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours are allowed for performing the first Surveillance after reaching 15% RTP. A power level of 15% RTP is chosen based on plant stability; i.e., the turbine generator is synchronized to the grid and rod control is in the automatic mode. The 24-hour allowance after increasing THERMAL POWER above 15% RTP provides a reasonable time to attain a scheduled power plateau, establish the requisite conditions, perform the required calorimetric measurement and make any required adjustments in a controlled, orderly manner and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be acceptable for subsequent use.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate that a difference of more than +2% RTP between the calorimetric heat balance calculation and NIS Power Range channel output or N-16 Power Monitor output is not expected in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(Δq) input to the overtemperature N-16 Function.

A Note clarifies that the Surveillance is required only if reactor power is ≥ 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP. The Note allows power ascensions and associated testing to be conducted in a controlled and orderly manner, at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE. Due to such effects as shadowing from the relatively deep control rod insertion and, to a lesser extent, the dependency of the axially-dependent radial leakage on the power level, the relationship between the incore and excore indications of axial flux difference (AFD) at lower power levels is variable. Thus, it is acceptable to defer the calibration of the excore AFD against the incore AFD until more stable conditions are attained (i.e, withdrawn control rods and a higher power level). The AFD is used as an input to the Overtemperature N-16 reactor trip function and for assessing compliance with LCO 3.2.3, “Axial Flux Difference.” Due to the DNB benefits gained by administratively restricting the power level to 50% RTP, no limits on AFD are imposed below 50% RTP by LCO 3.2.3; thus, the proposed change is consistent with the LCO 3.2.3 requirements below 50% RTP. Similarly, sufficient DNB margins are realized through operation below 50% RTP that the intended function of the Overtemperature N-16 reactor trip function is maintained, even though the excore AFD indication may not exactly match the incore AFD indication. Based on plant operating experience, 24 hours is a reasonable time frame to limit operation above 50% RTP while completing the procedural steps associated with the surveillance in an orderly manner.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 62 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices. The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local manual shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 62 days on a STAGGERED TEST BASIS is justified in Reference 12.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 12.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the core power distribution measurement. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the core power distribution measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(Δq) input to the overtemperature N-16 Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is ≥ 75% RTP and that 72 hours is allowed for performing the first surveillance after reaching equilibrium conditions at a THERMAL POWER ≥ 75% RTP. The SR is deferred until a scheduled testing plateau above 75% is attained during the post-outage power ascension. During a typical post-refueling power ascension, it is usually necessary to control the axial flux difference at lower power levels through control rod insertion. Due to rod shadowing effects and, to a lesser degree,

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

the dependency of the axially-dependent radial leakage on the power level, the incore-excore AFD relationship well below 75% RTP may differ excessively from the incore-excore axial flux difference relationship at full power. Excore calibration adjustments should be based on the incore-excore multipoint relationship established above 75% RTP by use of the developed calibration standard equations or by initiating an AFW swing and performing a direct multipoint measurement. After equilibrium conditions are achieved at the specified power plateau, a full core flux map must be taken, and the required data collected. The data is typically analyzed and the appropriate excore calibrations are completed within 48 hours after achieving equilibrium conditions. An additional time allowance of 24 hours is provided during which the effects of equipment failures may be remedied and any required re-testing may be performed.

The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascensions and associated testing to be conducted in a controlled and orderly manner, at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be acceptable for subsequent use. The benefit gained by operating at reduced power levels is sufficient to offset potential differences between the incore and excore indications of Δq prior to completion of this surveillance.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days. A COT is performed on each required channel to ensure the channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

SR 3.3.1.7 is modified by two Notes. Note 1 provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. Note 2 requires that the quarterly COT for the source range instrumentation include verification by observation of the associated permissive annunciator

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

window that the P-6 and P-10 interlocks are in their required state for the existing unit conditions.

SR 3.3.1.7 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

The Frequency of 184 days is justified in Reference 12.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, and it is modified by the same Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit conditions. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed e.g., by observation of the associated permissive annunciator window, within 184 days of the Frequencies prior to reactor startup, up to 12 hours after reducing power below P-10, and four hours after reducing power below P-6, as discussed below. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "12 hours after reducing power

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 184 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 12 hour or 4 hour limit, as applicable. These time limits are reasonable, based on operating experience, to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for the periods discussed above. The Frequency of 184 days is justified in Reference 12.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 5.

This SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

This SR is modified by Note 1 stating that N-16 detectors are excluded from the CHANNEL CALIBRATION because the unit must be in at least MODE 1 to obtain N-16 indications. However, after achieving equilibrium conditions

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

in MODE 1, detector plateau curves should be obtained, evaluated and compared to manufacturer's data.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology.

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

SR 3.3.1.10 is modified by Note 2 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This surveillance does not include verification of time delay relays. These relays are verified via response time testing per SR 3.3.1.16. Whenever an RTD is replaced in Functions 6 or 7, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares other sensing elements with the recently installed element.

The SR is modified by Note 3 stating that, prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP.

SR 3.3.1.10 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. For the intermediate and power range channels, detector plateau curves are obtained, evaluated and compared to manufacturer's data. The CHANNEL CALIBRATION for the source range neutron detectors consists of obtaining the detector plateau curves, evaluating those curves, and comparing the curves to the manufacturer's data. Note 3 states that, prior to entry into MODES 2 or 1, the power and intermediate range detector plateau voltage verification is not required to be current until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform a meaningful detector plateau voltage verification. The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascension testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE for subsequent use. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

SR 3.3.1.11 is modified by Note 2 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This surveillance does not include verification of time delay relays. These relays are verified via response time testing per SR 3.3.1.16.

SR 3.3.1.12

Not Used.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RTS interlocks every 18 months.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.13 (continued)

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, and the SI Input from ESFAS, and the Reactor Trip Bypass Breaker undervoltage trip mechanisms. This TADOT is performed every 18 months.

The Manual Reactor Trip TADOT shall independently verify the OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip mechanism.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.16

SR 3.3.1.16 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. The required trip initiation signals and acceptance criteria for response time testing are included in Technical Requirements Manual, (Ref. 6). No credit was taken in the safety analyses for those channels with response time listed as N.A. No response time testing requirements apply where N.A. is listed in the TRM. Individual component response times are not modeled in the analyses. The analyses model the overall or total

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor until loss of stationary gripper coil voltage.

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function time constants set at their nominal values.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be used for selected components provided that the components and methodology for verification have been previously NRC approved.

As appropriate, each channel's response time must be verified every 18 months on a STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices is included in the testing. Some portions of the response time testing cannot be performed during unit operation because equipment operation is required to measure response times. 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. Response time verification in lieu of actual testing may be performed on RTS components in accordance with reference 10.

SR 3.3.1.16 is modified by a Note stating that neutron and N-16 gamma detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. Response time of the neutron flux or N-16 signal portion of the channel shall be measured from detector output or input to the first electronic component in the channel.

REFERENCES

1. FSAR, Chapter 7.

2. FSAR, Chapter 15.

3. IEEE-279-1971.

(continued)

BASES

REFERENCES (continued)

4. 10 CFR 50.49.

5. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

6. Technical Requirements Manual.

7. Not Used.

8. WCAP-10271-P-A, Supplement 3, September 1990.

9. "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1," WCAP-12123, Revision 2, April, 1989.

10. “Elimination of Periodic Protection Channel Response Time Tests”, WCAP-14036-P-A, Revision 1, October 6, 1998.

11. “Probabilistic Risk Analysis of the RTS and ESFAS Test Times and Completion Times,” WCAP-14333-P-A, Revision 1, October 1998.

12. “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” WCAP-15376-P-A, Revision 1, March 2003.

13. Westinghouse letter WOG-06-17, “WCAP-10271-P-A Justification for Bypass Time and Completion Time Technical Specification Changes for Reactor Trip on Turbine Trip (ITSWG Action Item #314),” dated January 20, 2006.

Table B 3.3.1-1 (Page 1 of 2)
Reactor Trip System Setpoints

FUNCTION	NOMINAL TRIP SETPOINT
1. Manual Rector Trip	N/A
2. a. Power Range Neutron Flux, High	109% RTP
2. b. Power Range Neutron Flux, Low	25% RTP
3. Power Range Neutron Flux Rate, High Positive Rate	5% RTP with a time constant $\geq$ 2 seconds
4. Intermediate Range Neutron Flux, High	25% RTP
5. Source Range Neutron Flux, High	10^5 cps
6. Overtemperature N-16	See Note 1, Table 3.3.1-1
7. Overpower N-16	112% RTP[(a)]
8. a. Pressurizer Pressure, Low	1880 psig
8. b. Pressurizer Pressure, High	2385 psig
9. Pressurizer Water Level - High	92% span
10. Reactor Coolant Flow - Low	90% of nominal flow
11. Not Used.	
12. Undervoltage RCPs	4830 volts
13. Underfrequency RCPs	57.2 Hz
14. Steam Generator Water Level - Low-Low	38% NR (Unit 1) 35.4% NR (Unit 2)
15. Not Used.	
16. Turbine Trip	
a. Low Fluid Oil Pressure	59 psig
b. Turbine Stop Valve Closure	1% open

(a) Overpower N-16 Trip Setpoint will remain at 110% RTP for Unit 1, Cycle 13.

Table B 3.3.1-1 (Page 2 of 2)
Reactor Trip System Setpoints

FUNCTION	NOMINAL TRIP SETPOINT
17. SI Input form ESFAS	NA
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	1 x 10^{-10} amps
b. Low Power Reactor Trips Block, P-7	NA
c. Power Range Neutron Flux, P-8	48% of RTP
d. Power Range Neutron Flux, P-9	50% of RTP
e. Power Range Neutron Flux, P-10	10% of RTP
f. Turbine First Stage Pressure, P-13	10% turbine power
19. Reactor Trip Breakers	NA
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	NA
21. Automatic Trip Logic	NA

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;
- Signal processing equipment including 7300 process Instrumentation and Control system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications; and
- Solid State Protection System (SSPS) including input, logic, and output bays: initiates the proper unit shutdown or engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for ESFAS action to prevent exceeding acceptable limits such that the consequences of Design Basis Accidents (DBAs) will be acceptable.

The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although the channel is OPERABLE under these circumstances, the ESFAS setpoint must be left adjusted to a value within the established calibration tolerance band of the ESFAS setpoint in accordance with the uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the allowances of the uncertainty terms assigned.

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BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values is determined by either “as-found” calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of- two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

(continued)

BASES

BACKGROUND (continued)

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Allowable Values and Trip Setpoints

The trip setpoints used in the bistables are based on the analytical limits stated in Reference 3. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservative with respect to the analytical limits. Detailed descriptions of the methodologies used to calculate the trip setpoints, including their explicit uncertainties, are provided in the setpoint calculations. The methodology to derive the trip setpoints is based upon combining all of the uncertainties in the channels. The essential elements of the methodology for all functions except 5b and 6c are described in Reference 9.

Changes in accordance with this methodology have been reviewed by the staff in the original Unit 2 Technical Specifications and in several subsequent license amendments (e.g., amendments 21/7 and 22/8 to the Unit 1/Unit 2 Technical Specifications). The actual nominal ESFAS setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. The Allowable Value serves as the Technical Specification operability limit for the purpose of the COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints adjusted consistent with the requirements of the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

The ESFAS setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The ESFAS setpoint value ensures the safety analysis limits are met for the time period of the surveillance interval when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the “as left” setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The ESFAS setpoint value of Table B3.3.2-1 is therefore

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BASES

BACKGROUND (continued)

considered a "nominal" value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION for all functions except 5b and 6c. The methodology used to calculate the Nominal Trip Setpoints for Functions 5b and 6c in Table B 3.3.2-1 is the same basic square-root-sum-of-squares (SRSS) methodology with the inclusion of refinements to better reflect plant calibration practices and equipment performance. The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

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

The Allowable Values for Functions 5b and 6c in the accompanying LCO are based on the Nominal Trip Setpoints and are determined by subtracting (for low setpoint trips) or adding (for high setpoint trips) the rack calibration accuracy from/to the Nominal Trip Setpoint. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit.

(continued)

BASES

BACKGROUND (continued)

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each SSPS train has a built in testing device that can automatically test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

The actuation of ESF components is accomplished through master and slave relays. The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented by the SLAVE RELAY TEST circuit, and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

A channel is OPERABLE with a setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the calibration tolerance band of the Nominal Trip Setpoint except for functions 5b and 6c. Note (q) requires the instrument channel setpoint for a channel in these Functions to be reset to a value within the as-left setpoint tolerance band for that channel on either side of the Nominal Trip Setpoint, or to a value that is more conservative than the Nominal Trip Setpoint. The conservative direction is indicated by the direction of the inequality sign applied to the Nominal Trip Setpoint in Bases Table B 3.3.2-1. Setpoint restoration and post-test verification assure that the assumptions in the plant setpoint methodology are satisfied in order to protect the safety analysis limits. Note (q) preserves the safety analysis limits. If the channel can not be reset to a value within its as-left setpoint tolerance band, or to a value that is more conservative than the Nominal Trip Setpoint if required based on plant conditions, the channel shall be declared inoerpable and the applicable Required Actions are taken. The methodology used to determine the as-left setpoint tolerance band is based on the square-root-sum-of-squares (SRSS) of the tolerances applicable to the instrument loop or sub-loop constituents being tested. The applicability of notes (q) and (r) for Unit 1, items 2a, 2b, 6, and 7 will begin following the completion of Cycle 13. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an

ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS. The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (e.g., coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

These functions are necessary to mitigate the effects of certain high energy line breaks (HELBs) both inside and outside of containment as described in the FSAR [Ref. 3]. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Ventilation Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps;
- Enabling semi-automatic switchover of Emergency Core Cooling Systems (ECCS) suction to containment sumps, coincident with RWST low-low level.
- Emergency DG start;
- Start of station service water pumps;
- Start of component cooling water pumps;
- Start of Containment Spray Pumps; and
- Start of essential ventilation systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability;
- Isolation of the control room to ensure habitability; and
- Enabling ECCS suction from the refueling water storage tank (RWST) switchover on low low RWST level to ensure continued cooling via use of the containment sump.
- Emergency loads for LOCA are properly sequenced and powered;
- Essential cooling for ESF/ESF support equipment; and
- Start of SSW and CCW systems to service safety-related systems.

a. Safety Injection - Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate SI at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one handswitch and the interconnecting wiring to the actuation logic cabinet. Each handswitch actuates both trains. This configuration does not allow testing at power.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Safety Injection - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection - Containment Pressure-High 1

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Containment Pressure-High 1 provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High 1 must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to significantly pressurize the containment.

d. Safety Injection - Pressurizer Pressure-Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

The pressurizer pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, and SI. Therefore, the actuation logic must be able to withstand both an input failure to control system, which may then require the protection function actuation, and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11 and below P-11, unless the Safety Injection - Pressurizer Pressure-Low Function is blocked) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure-High 1 signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection - Steam Line Pressure-Low

Steam Line Pressure-Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure-Low provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

With the transmitters typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

This Function is anticipatory in nature and has a lead/lag ratio of 50/5.

Steam Line Pressure-Low must be OPERABLE in MODES 1, 2, and 3 (above P-11 and below P-11, unless the Safety Injection - Steam Line Pressure-Low Function is blocked) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern. Inside containment SLB will be terminated by automatic SI actuation via Containment Pressure-High 1, and outside containment SLB will be terminated by the Steam Line Pressure-Negative Rate-High signal for steam line isolation. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to be of concern.

2. <u>Containment Spray</u>

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

2. Reduces the amount of radioactive iodine in the containment atmosphere; and

3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure; and

- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps and mixed with a sodium hydroxide solution from the spray additive tank. When the RWST reaches the empty level setpoint, the spray pump suctions are manually realigned to the containment sumps if continued containment spray is required. Containment spray is actuated by Containment Pressure-High 3.

a. <u>Containment Spray - Manual Initiation</u>

The operator can initiate containment spray at any time from the control room by simultaneously turning two containment spray actuation switches in the same train. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned simultaneously to initiate containment spray. There are two sets of two switches each in the control room.

Simultaneously turning the two switches in either set will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two Manual Initiation switches in each train are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation.

b. <u>Containment Spray - Automatic Actuation Logic and Actuation Relays</u>

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a containment spray, actuation is simplified by the use of the manual actuation hand switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray - Containment Pressure

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This is one of the only Functions that requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, since the consequences of an inadvertent actuation of containment spray could be serious. Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.

Four channels are used in a two-out-of-four logic configuration. This configuration is called the Containment Pressure-High 3 Setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Additional redundancy is warranted because this Function is energize to trip. Containment Pressure-High 3 must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure-High 3 setpoint.

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines, except component cooling water (CCW) to the reactor coolant pumps, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation logic. All process lines penetrating containment, with the exception of CCW, are isolated.

CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers, motor air coolers, and upper and lower bearing coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room. Either switch actuates both trains.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment.

Phase B containment isolation is actuated by Containment Pressure-High 3 or manually, via the automatic actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure-High 3, a large break LOCA or SLB must have occurred. RCP operation will no longer be required and CCW to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches in either set are turned simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. <u>Containment Isolation - Phase A Isolation</u>

(1) <u>Phase A Isolation - Manual Initiation</u>

Manual Phase A Containment Isolation is actuated by either of two switches in the control room.

Either switch actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Vent Isolation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(2) Phase A Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation handswitches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation - Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation - Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to minimize the potential of spurious trips that may damage the RCPs.

(1) Phase B Isolation - Manual Initiation

(2) Phase B Isolation - Automatic Actuation Logic and Actuation Relays

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation handswitches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation.

In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B containment isolation.

There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase B Isolation - Containment Pressure

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize. Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

a. <u>Steam Line Isolation - Manual Initiation</u>

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two switches in the control room and either switch can initiate action to immediately close all MSIVs. The LCO requires two channels to be OPERABLE.

b. <u>Steam Line Isolation - Automatic Actuation Logic and Actuation Relays</u>

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident.

This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs and their associated upstream drip pot isolation valves are closed and deactivated. In this condition, the isolation function is complete; therefore, the isolation actuation instrumentation is not required to be OPERABLE. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Steam Line Isolation - Containment Pressure-High 2

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. Containment Pressure-High 2 provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High 2 must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed and deactivated. In MODE 4 the increase in containment pressure following a pipe break would occur over a relatively long time period such that manual action could reasonably be expected to provide protection and ESFAS Function 4.c need not be OPERABLE. In MODES 5 and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure-High 2 setpoint.

d. Steam Line Isolation - Steam Line Pressure

(1) Steam Line Pressure-Low

Steam Line Pressure-Low provides closure of the MSIVs in the event of an SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure-Low was discussed previously under SI Function 1.e.1. Steam Line Pressure-Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. If not blocked below P-11, the Steam Line Pressure-Low Function must be OPERABLE. When blocked, an inside containment SLB will be terminated by automatic actuation via Containment Pressure-High 2. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure - Negative Rate-High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and deactivated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have a significant effect on required plant equipment.

(2) Steam Line Pressure - Negative Rate-High

Steam Line Pressure - Negative Rate-High provides closure of the MSIVs for an SLB when less than the P-11 setpoint to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure-Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure - Negative Rate-High signal is automatically enabled. Steam Line Pressure - Negative Rate-High provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy requirements with a two-out-of-three logic.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Steam Line Pressure - Negative Rate-High must be OPERABLE in MODE 3 when the Steamline Pressure-Low signal is blocked, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically disabled and the Steam Line Pressure-Low signal is automatically enabled. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and deactivated. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of significant enough quantities of energy to cause a significant cooldown of the RCS. While the transmitters may experience elevated ambient temperatures due to an SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

5. Turbine Trip and Feedwater Isolation

The primary functions of the Turbine Trip and Feedwater Isolation signals are to prevent damage to the turbine due to water in the steam lines and to stop the excessive flow of feedwater into the SGs. These Functions are necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

Those functions that use the Turbine Trip and Feedwater Isolation signals are listed below; however, the LCO only requires the main turbine trip and feedwater isolation functions to be operable. The remaining functions use the Turbine Trip and Feedwater Isolation signal, but are not credited in the accident analyses.

The Function is actuated when the water level in any SG exceeds the high high setpoint and performs the following functions:

- Trips the main turbine;

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Initiates feedwater isolation;
- Trips the MFW pumps and initiates closure of the main feedwater pump discharge valves; and
- Closes the MFW control valves and the bypass feedwater control valves.

This Function is actuated by SG Water Level-High High or by an SI signal. The RTS also initiates a turbine trip signal whenever a reactor trip (P-4) is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was previously discussed.

a. <u>Turbine Trip and Feedwater Isolation - Automatic Actuation Logic and Actuation Relays</u>

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. <u>Turbine Trip and Feedwater Isolation - Steam Generator Water Level-High High (P-14)</u>

This signal provides protection against excessive feedwater flow. The SG water level instruments provide input to the SG Water Level Control System; however, the three SG water level instrument channels used for the P-14 function are not normally used for this function. The actuation logic must be able to withstand a single failure in the channels providing the protection function actuation. The number of operable channels is modified by a note which allows an alternate arrangement. The CPSES design has four SG water level channels. One channel is normally used as input to the SG water level controller and three channels are designated for use with the P-14 function. However, if the channel normally used as input to the SG water level controller is inoperable, one of the channels providing input to the P-14 interlock may be used to provide input to the steam generator water level control signal on the condition that the P-14 bistable on that channel is declared inoperable. In this condition, the actuation logic is able to withstand both an input failure to the

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

control system, which may then require a protection function actuation, and a single failure in the other channels providing the protection function actuation. In this condition, three OPERABLE channels are required to satisfy the requirements with one-out-of-three logic.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

c. Turbine Trip and Feedwater Isolation - Safety Injection

Turbine Trip and Feedwater Isolation are also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

Turbine Trip and Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 except when all MFIVs, main feedwater control valves, and associated bypass valves (see B 3.7.3) are closed and deactivated or isolated by a closed manual valve when the MFW System is in operation. In MODES 3, 4, 5, and 6, this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST). Upon low level in the CST, the pump suctions can be manually realigned to the safety-related Station Service Water (SSW) System. The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays (Solid State Protection System)

Automatic actuation logic and actuation relays consist of the similar features and operate in the similar manner as described for ESFAS Function 1.b.

b. Not used.

c. Auxiliary Feedwater - Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level-Low Low provides input to the SG Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system which may then require a protection function actuation and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with two-out-of-four logic. Two-out-of-four low-low level signals in any SG starts the motor-driven AFW pumps; in two or more SGs starts the turbine-driven AFW pump.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

d. Auxiliary Feedwater - Safety Injection

An SI signal starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

e. Auxiliary Feedwater - Loss of Offsite Power

A loss of power to the reactor coolant pumps will result in a reactor trip and the subsequent need for some method of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

decay heat removal. During a loss of offsite power, to both safety related busses feeding the motor driven AFW pumps, the loss of power to the bus feeding the turbine driven AFW pump valve control motor will start the turbine driven AFW pump to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip. In addition, once the diesel generators are started and up to speed, the motor driven AFW pumps will be sequentially loaded onto the diesel generator busses.

Functions 6.a through 6.e must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level-Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level-Low Low in any two operating SGs will cause the turbine driven pumps to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

f. Not Used

g. <u>Auxiliary Feedwater - Trip of All Main Feedwater Pumps</u>

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MFW pump is equipped with two pressure switches on the oil line for the speed control system. # Train ”A” and a Train “B” sensor is on each MFW pump. The Train “A(B)” trip signals from both MFW pumps are required to actuate the Train “A(B)” motor-driven auxiliary feedwater pump. A trip of all MFW pumps starts the motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Function 6.g must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus pump trip is not indicative of a condition requiring automatic AFW initiation.

h. Not Used.

7. Automatic Switchover to Containment Sump

At the end of the injection phase of a LOCA, the RWST will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the RHR pumps is semi-automatically switched to the containment recirculation sumps. After switching the low head residual heat removal (RHR) pumps draw the water from the containment recirculation sump, the RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the suction of the other ECCS pumps. Switchover from the RWST to the containment sump must occur before the RWST Empty setpoint. Switchover of the containment spray pumps from the RWST to the containment sump is performed manually after completion of ECCS switchover, but before the Empty setpoint is reached. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ESF pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. Raising the nominal RWST level at which Operations starts switchover (33%) would require prior NRC approval. This ensures the reactor remains shut down in the recirculation mode.

a. Automatic Switchover to Containment Sump - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Automatic Switchover to Containment Sump - Refueling Water Storage Tank (RWST) Level-Low Low Coincident With Safety Injection

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low low level in the

RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the ECCS injection phase of the LOCA. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability.

The RWST - Low Low Allowable Value/Trip Setpoint is selected to ensure switchover manual actions are not required until 10 minutes after the event initiation.

The transmitters are located in an area not affected by HELBs or post accident high radiation. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Semi-Automatic switchover begins only if the RWST low low level signal is coincident with SI. This prevents accidental switchover during normal operation. Accidental switchover could result in backflow to an empty sump. The semi-automatic switchover Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

This Function must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the ECCS pumps. This Function is not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. System pressure and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

8. Engineered Safety Feature Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure by passable functions are in operation under the conditions assumed in the safety analyses.

a. Engineered Safety Feature Actuation System Interlocks - Reactor Trip, P-4

The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. The P-4 permissive also prevents re-actuation of safety injection after a manual reset of safety injection following at least a 60 second delay time. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed.

Those functions that use the P-4 interlock are listed below; however, the LCO only requires the main turbine trip function to be operable. The remaining functions use a signal associated with the P-4 interlock, but are not credited in the accident analyses.

- Trips the main turbine;
- Isolates MFW with coincident low T_{avg};
- Prevent automatic reactuation of SI after a manual reset of SI;
- Allows arming of the steam dump valves and transfers the steam dump from the load rejection T_{avg} controller to the plant trip controller; and

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Prevents opening of the MFW isolation valves if they were closed on SI or SG Water Level-High High.

Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in core power. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. Only the turbine trip Function is explicitly assumed since it is an immediate consequence of the reactor trip Function. Neither turbine trip, nor any of the other four Functions associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are met.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a Trip Setpoint and Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality.

b. Engineered Safety Feature Actuation System Interlocks - Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal (previously discussed). When the Steam Line Pressure-Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure - Negative Rate-High is automatically enabled. This provides protection for an SLB by closure of the MSIVs. With two-out-of-three pressurizer

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

pressure channels above the P-11 setpoint, the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset. When the Steam Line Pressure-Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure - Negative Rate-High is disabled. The Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4,5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

The ESFAS instrumentation satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per pump, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

(continued)

BASES

ACTIONS

A.1 (continued)

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the SSPS for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;

(continued)

BASES

ACTIONS

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

- Phase A Isolation;
- Phase B Isolation; and
- Semi-Automatic Switchover to Containment Sump.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time). The 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.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 6) that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions do not apply when a logic train is being tested under the 4 hour bypass Note of Condition C). Entry into Condition C is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition C is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition C entry. If this situation were to occur during the 24-hour Completion Time of Required Action C.2, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition C or fully implement these restriction or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

(continued)

BASES

ACTIONS

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

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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

Condition D applies to:

- Containment Pressure-High 1;

- Pressurizer Pressure-Low;

- Steam Line Pressure-Low;

- Containment Pressure-High 2;

- Steam Line Pressure - Negative Rate-High; and

- SG Water Level-Low Low.

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two

(continued)

BASES

ACTIONS

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

configuration. The inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 12.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 12.

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

Condition E applies to:

- Containment Spray Containment Pressure-High 3; and
- Containment Phase B Isolation Containment Pressure-High 3.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip

(continued)

BASES

ACTIONS

E.1, E.2.1, and E.2.2 (continued)

condition (assuming the inoperable channel has failed high). The completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The 12 hour time limit is justified in Reference 12.

F.1, F.2.1, and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation;
- Loss of Offsite Power; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. For the Loss of Offsite Power Function, this action recognizes the lack of manual trip provision for a failed channel. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

BASES

ACTIONS (continued)

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 6) assumption that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restriction do not apply when a logic train is being tested under the 4-hour bypass Note of Condition G). Entry into Condition G is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition G is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition G entry. If this situation were to occur during the 24-hour Completion Time of Required Action G.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition G or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

(continued)

BASES

ACTIONS

G.1, G.2.1 and G.2.2 (continued)

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a log train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

- To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause analog channels to be unavailable should not be scheduled when a logic train is inoperable for maintenance.

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., station service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Turbine Trip and Feedwater Isolation Function.

This action addresses the train orientation of the actuation logic for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. 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. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 6) assumption that 4 hours is the average time required to perform channel surveillance.

I.1 and I.2

Condition I applies to:

- SG Water Level-High High (P-14)

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two or one-out-of-three logic will result in actuation. The 72 hour Completion Time is justified in Reference 12. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 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. In MODE 3, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing surveillance testing. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 12.

J.1 and J.2

Condition J applies to the AFW pump start on trip of all MFW pumps.

This action addresses the train orientation of the SSPS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 6 hours are allowed to place it in the tripped condition. If the channel cannot be tripped in 6 hours, 6 additional hours are allowed to place the unit in MODE 3. 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

(continued)

BASES

ACTIONS

J.1 and J.2 (continued)

without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

K.1, K.2.1 and K.2.2

Condition K applies to:

- RWST Level-Low Low Coincident with Safety Injection.

RWST Level-Low Low Coincident With SI provides semi-automatic actuation of switchover to the containment recirculation sumps. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hour and 78 hour Completion Times are justified in References 8 and 12. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 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. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The total of 78 hours to reach MODE 3 and 12 hours for a second channel to be bypassed is acceptable based on the results of References 8 and 12.

L.1, L.2.1 and L.2.2

Condition L applies to the P-11 interlock.

(continued)

BASES

ACTIONS

L.1, L.2.1 and L.2.2 (continued)

With one or more required channel(s) inoperable, the operator must verify that the interlock is in the required state for the existing unit condition by observation of the permissive annunciator windows. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. 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.

The Frequency is based on 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 the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.2.3

Not used.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) is justified in Reference 6. The Frequency of 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint calculation. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint calculation.

SR 3.3.2.5 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

The Frequency of 184 days is justified in Reference 13.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function, or is placed in a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.6 (continued)

condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing contacts operated by the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

For ESFAS slave relays and auxiliary relays which are Westinghouse type AR relays, the SLAVE RELAY TEST is performed every 18 months. The Frequency is based on the slave relay reliability assessment presented in Reference 10. This reliability assessment is relay specific and applies only to Westinghouse type AR relays with AC coils. Note that, for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in Reference 10.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 31 days. This test is a check of the Loss of Offsite Power Function.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The SR is modified by a second note that excludes the actuation of final devices from the surveillance testing. The start of the auxiliary feedwater pumps during this SR is unnecessary as these pumps are adequately tested by the SRs for LCO 3.7.5. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. The Safety Injection TADOT shall independently verify the OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers as well as the contacts for safety injection actuation. It is performed every 18 months. As a minimum, each Manual Actuation Function is tested up to, but not including, the master relay coils. This test overlaps with the master relay coil testing performed in accordance with SR 3.3.2.4. The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.8 (continued)

SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology.

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

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.2.9 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

SR 3.3.2.10

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing, required channels, and acceptance criteria are included in the Technical Requirements Manual (Ref. 7). For each Functional Unit to which this SR applies, at least one ESF function has a required response time but not necessarily all associated ESF functions. No credit was taken in the safety analyses for those channels with response time listed as N.A. When the response time for a function in the TRM is NA, no specific testing need be performed to comply with this SR. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time testing may be performed with the transfer functions set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be used for selected components provided that the components and methodology for verification have been previously NRC approved.

ESF RESPONSE TIME tests are performed on an 18 month STAGGERED TEST BASIS. The testing shall include at least one train such that both trains are tested at least once per 36 months. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences. Response time verification in lieu of actual testing may be performed on ESFAS components in accordance with reference 11.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 532 psig in the SGs.

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor Trip Interlock. This Frequency is based on operating experience.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
7. Technical Requirements Manual.
8. WCAP-10271-P-A, Supplement 3, September 1990.
9. "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1," WCAP-12123, Revision 2, April, 1989.
10. WCAP-13877-P-A, Revision 2, August 2000.

(continued)

BASES

REFERENCES (continued)

11. “Elimination of Periodic Protection Channel Response Time Tests”, WCAP-14036-P-A, Revision 1, October 6, 1998.

12. “Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” WCAP-14333-P-A, Revision 1, October 1998.

13. “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” WCAP-15376-P-A, Revision 1, March 2003.

Table B 3.3.2-1 (Page 1 of 3)
ESFAS Trip Setpoints

FUNCTION	NOMINAL TRIP SETPOINT
1. Safety Injection	
a. Manual Initiation	NA
b. Automatic Actuation Logic and Actuation Relays	NA
c. Containment Pressure – High 1	3.2 psig
d. Pressurizer Pressure – Low	1820 psig
e. Steam Line Pressure – Low	605 psig $\tau_1 \geq 10$ seconds[a] $\tau_2 \leq 5$ seconds
2. Containment Spray	
a. Manual Initiation	NA
b. Automatic Actuation Logic and Actuation Relays	NA
c. Containment Pressure – High 3	18.2 psig
3. Containment Isolation	
a. Phase A Isolation	
(1) Manual Initiation	NA
(2) Automatic Actuation Logic and Actuation Relays	NA
(3) Safety Injection	See Function 1
b. Phase B Isolation	
(1) Manual Initiation	NA
(2) Automatic Actuation Logic and Actuation Relays	NA
(3) Containment Pressure - High 3	18.2 psig

(a) τ_1 will remain at 50 seconds for Unit 1, Cycle 13.

Table B 3.3.2-1 (Page 2 of 3)
ESFAS Trip Setpoints

FUNCTION	NOMINAL TRIP SETPOINT
4. Steam Line Isolation	
a. Manual Initiation	NA
b. Automatic Actuation Logic and Actuation Relays	NA
c. Containment Pressure - High 2	6.2 psig
d. Steam Line Pressure	
(1) Low	605 psig $\tau_1 \geq$ 10 seconds[a] $\tau_2 \leq$ 5 seconds
(2) Negative Rate - High	100 psi $\tau \geq$ 50 seconds
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays	NA
b. SG Water Level - High-High (P-14)	84% NR (Unit 1) 81.5% NR (Unit 2)
c. Safety Injection	See Function 1.
6. Auxiliary Feedwater	
a. Automatic Actuating Logic and Actuation Relays (SSPS)	NA
b. Not Used	
c. SG Water Level - Low-Low	38% NR (Unit 1) 35.4% NR (Unit 2)
d. Safety Injection	See Function 1.
e. Loss of Power	NA
f. Not Used	

(a) τ_1 will remain at 50 seconds for Unit 1, Cycle 13.

Table B 3.3.2-1 (Page 3 of 3)
ESFAS Trip Setpoints

FUNCTION	NOMINAL TRIP SETPOINT
6. Auxiliary Feedwater (continued)	
g. Trip of All Main Feedwater Pumps	NA
h. Not Used.	
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays	NA
b. Refueling Water Storage Tank (RWST) Level -Low-Low Coincident with Safety Injection	33.0%
8. ESFAS Interlocks	
a. Reactor Trip, P-4	NA
b. Pressurizer Pressure, P-11	1960 psig

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis 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 the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (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 include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A Category 1 variables and selected non-Type A Category 1 variables.

All Type A Category 1 variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

Selected Non-Type A, Category 1 variables are deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and
- Provide information regarding the potential 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.

(continued)

BASES

BACKGROUND (continued)

These variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and non-Type A Category 1 variables and provide justification for deviating from the NRC proposed list of Category 1 variables.

The selected non-Type A Category 1 variables are Reactor Vessel Water Level and Containment Area Radiation (High Range). These selected variables are considered essential to the operator for LOCA management. Non-Type A Category 1 variables that are not included are Neutron Flux, Containment Pressure (Wide Range), Steam Generator Water Level (Wide Range), and Containment Isolation Valve Status. Although they are important variables, effectiveness of the operator response to a DBA would not be reduced because other variables provide sufficient in formation for operator response. Neutron Flux is not required since reactor coolant temperatures provide sufficient confirmation of subcriticality. Containment Pressure (WR) is not required since the Containment Pressure intermediate range exceeds the containment design pressure and would provide sufficient confirmation of peak containment pressure. Steam Generator Water Level (WR) is not required since the Steam Generator water level narrow range would provide sufficient confirmation of level. The Wide range level is included as an alternative to auxiliary feedwater flow. Containment Isolation Valve Status is not a CPSES Category 1 variable.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and selected non-Type A Category 1 variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;
- Determine whether systems important to safety are performing their intended functions;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine the likelihood of 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 to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Selected Category 1, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, selected Category 1, non-Type A, variables are important for reducing public risk and satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A instrumentation, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses selected Regulatory Guide 1.97 instruments that have been designated Category 1, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels to ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident. Even though only one RCS T_{cold} and T_{hot} indication per RCS loop is available, other PAM indications provide the necessary redundancy.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

Additional channels and/or variables are normally available to resolve information ambiguity should the redundant displays disagree.

(continued)

LCO (continued)

Table 3.3.3-1 provides a list of variables identified by the unit specific Regulatory Guide 1.97 (Ref. 1) analyses.

Type A and Category 1 variables are required to meet Regulatory Guide 1.97 Category 1 (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Refueling Water Storage Tank (RWST) Level

   Refueling Water Storage Tank Level is a Type A Category 1 variable for determining switchover of Containment Spray to the Containment Emergency Sump. This level indication is provided for the operators to assist in monitoring and ensuring an adequate supply of water for safety injection and containment spray.

2. Subcooling Monitors

   RCS Subcooling Monitors are Type A Category 1 variables for RCS subcooling (SI termination/reinitiation), natural circulation and RCP trip. RCS Subcooling Monitors are also Type B Category 1 variables for monitoring the core cooling status tree. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

   RCS Hot and Cold Leg Temperatures are Type A, Category 1 variables for maintaining proper natural circulation conditions and to control heat removal rates. RCS Hot and Cold Leg Temperatures are also Type B Category 1 variables provided for monitoring RCS integrity status tree.

   RCS hot and cold leg temperatures (T_{hot} and T_{cold}, respectively) are used to provide input to the Subcooling Monitor.

(continued)

BASES

LCO

3,4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range) (continued)

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS.

Each of the four hot legs and each of the four RCS cold legs has one wide-range, fast response RTD. The channels are required to provide indication over a range of 50°F to 700°F (Ref. 2).

5. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Type A Category 1 variable for RCS subcooling (SI termination/reinitiation), RCP trip and event diagnosis. RCS wide range pressure is also a Type B and C Category I variable provided for monitoring RCS integrity.

RCS pressure is used to verify delivery of SI flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure is also used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

(continued)

BASES

LCO

5. Reactor Coolant System Pressure (Wide Range) (continued)

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

6. Reactor Vessel Water Level

Reactor Vessel Water Level is a Type B Category 1 variable for monitoring the core cooling and inventory status trees referenced in the Emergency Operating Procedures (EOPs). Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

The Reactor Vessel Level Indicating System (RVLIS) provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

7. Containment Sump Water Level (Wide Range)

Containment Sump Water Level (Wide Range) is a Type A Category 1 variable for event diagnosis and determining switchover of ECCS

(continued)

BASES

LCO

7. Containment Sump Water Level (Wide Range) (continued)

suction. It is also a Type B Category 1 variable for monitoring containment status tree. Containment Sump Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used to determine:

- containment sump level accident diagnosis;
- when to begin the recirculation procedure; and
- whether to terminate SI, if still in progress.

8. Containment Pressure (Intermediate Range)

Containment Pressure (Intermediate Range) is a Type A Category 1 variable. It is a Type B Category 1 variable for monitoring containment status tree. Containment Pressure (Intermediate Range) is provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to verify closure of main steam isolation valves (MSIVs), and containment spray Phase B isolation when High-3 containment pressure is reached.

9. Main Steam Line Pressure (Steam Generator Pressure)

Main Steam Line Pressure (Steam Generator Pressure) is a Type A Category 1 variable for event diagnosis, natural circulation, and RCP trip criteria. It is also a Type B Category 1 variable for monitoring heat sink status tree. It is a variable for determining if a secondary pipe rupture has occurred. This indication is provided to aid the operator in the identification of the faulted steam generator and to verify natural circulation.

10. Containment Area Radiation (High Range)

Containment Area Radiation Level (High Range) is a Type E Category 1 variable used to determine if an adverse containment environment exists due to a high containment radiation level. Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

(continued)

BASES

LCO (continued)

11. Deleted

12. Pressurizer Water Level

Pressurizer Water Level is Type A Category 1 variable for SI termination/reinitiation. It is also Type B Category 1 for monitoring RCS inventory status tree. Pressurizer Level is used to determine whether to terminate 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.

13. Steam Generator Water Level (Narrow Range)

Steam Generator Water Level (Narrow Range) is a Type A Category 1 variable for Steam Generator Tube Rupture event diagnosis and SI termination. It is also a Type B Category 1 variable for verification of heat sink.

SG Water Level (Narrow Range) is used to:

- identify the faulted SG following a tube rupture;
- verify that the intact SGs are an adequate heat sink for the reactor;
- determine the nature of the accident in progress (e.g., verify an SGTR); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

Operator action is based on the control room indication of SG level. The RCS response during a design basis small break LOCA depends on the break size. For a certain range of break sizes, the boiler condenser mode of heat transfer (reflux cooling) supplements other forms of decay heat removal. Steam generator water level (narrow range) is a Type A variable because the operator must manually control SG level to establish an adequate heat sink. If the steam generator water level (narrow range) indication is on-scale (including uncertainties), adequate heat sink to support reflux cooling exists.

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BASES

LCO (continued)

14. Condensate Storage Tank (CST) Level

Condensate Storage tank Level is a Type A Category 1 variable for determining adequate water for auxiliary feedwater pumps and for switchover to station service water. CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides a safety grade water supply for the AFW System. Inventory is monitored by redundant 0 to 100% level indication for each tank. CST Level is displayed on a control room indicator and unit computer. In addition, a control room annunciator alarms on low level.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), feedline break (FLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from station service water.

15, 16, 17, 18. Core Exit Temperature

Core exit temperature is a Type A Category 1 variable for natural circulation, SI reduction/termination/reinitiation, and RCP trip. It is also a Type B Category 1 variable for monitoring core cooling status tree. It is a Type C Category 1 variable for monitoring the potential for fuel clad breach. Core Exit Temperature is provided for verification and long term surveillance of core cooling (Refs 1, 2 and 3).

An evaluation was made of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to provide the emergency response guideline inputs for determination of inadequate core cooling and for determination of subcooling. Based on these evaluations, adequate core cooling is ensured with a minimum of five CETs per train. These five CETs per train cannot be in the outer two rows of assemblies since they can receive significant cooling from steam generator drainage due to refluxing. Twenty CETs (8 Train A and 12 Train B) are in the outer two rows of assemblies. 30 CETS (17 Train A and 13 Train B) are not in the outer two rows of assemblies. The minimum set of five CETS should

(continued)

BASES

LCO

15, 16, 17, 18 Core Exit Temperature (continued)

include one CET per quadrant per train and one additional CET per train centrally located in the core. Of the 30 available CETs, six CETs per Train are centrally located. Two trains of CETs ensure a single failure will not disable the ability to determine the adequacy of core cooling.

To satisfy the LCO:

1. Two OPERABLE channels (consisting of at least two CETs each) of Core Exit Temperature are required in each quadrant,

2. Of the CETs in 1 above, at least one per train per quadrant must be located in other than the two outer rows of assemblies, and

3. Of the CETs in 1 above (but not one of the CETS in 2 above), at least one CET per train must be centrally located in core.

CETs also provide input to the Subcooling Monitor.

19. Auxiliary Feedwater Flow Rate and Steam Generator Water Level (Wide Range)

Auxiliary Feedwater Flow is a Type A Category 1 variable for SI termination and determination of adequate/inadequate heat sink. It is also a Type B Category 1 variable for monitoring the heat sink status tree. Steam Generator water Level (Wide Range) is a Type B Category 1 variable for monitoring the heat sink status tree. It is also a backup for auxiliary feedwater flow. AFW Flow is provided to monitor operation of decay heat removal via the SGs. The LCO requires that either 2 channels of AFW per SG are OPERABLE, or that one channel of AFW and one channel of SG water level (wide range) be operable.

The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 550 gpm. Redundant monitoring capability is provided by two independent trains of flow instrumentation for each SG. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

(continued)

BASES

LCO

19. Auxiliary Feedwater Flow Rate and Steam Generator Water Level (Wide Range) (continued)

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level. Therefore, steam generator water level (wide range) may be used in lieu of the same train of AFW flow for a given steam generator. Steam generators 1 and 3 have Train A wide range level, while steam generators 2 and 4 have Train B wide range level.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function. When the Required Channels in Table 3.3.3-1 are specified on a per SG, per loop or per steamline basis, then the Condition may be entered separately for each SG, loop or steamline, as appropriate.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required

(continued)

ACTIONS

A.1 (continued)

channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.8, which requires a written report to be submitted to the NRC within the following 14 days. 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.

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function; one required T_{hot} channel and one required Core Exit Temperature channel inoperable or one required T_{cold} channel and one required Steam Line Pressure channel for the associated loop inoperable). Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate 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 qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C is not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C, and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Action and associated Completion Time of Condition C is not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where 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

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be temporarily used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. 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.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

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

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized. All of the instruments listed in Table 3.3.3-1 are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that 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 the LCO required channels.

SR 3.3.3.2

Deleted

SR 3.3.3.3

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." Whenever an RTD is replaced in Function 3 or 4, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares other sensing elements with the recently installed element. Whenever a core exit thermocouple replaced in Functions 15 thru 18, the next required CHANNEL CALIBRATION of the core exit thermocouples is accomplished by an in-place 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. Containment Radiation Level (High Range) CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10R/hr and a one point calibration check of the detector below 10R/hr with an installed or portable gamma source.

(continued)

BASES (continued)

REFERENCES

1. FSAR Section 7.5.
2. Regulatory Guide 1.97, Revision 2, December 1980.
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. Not used
5. Generic Letter 83-37, NUREG-0373 Technical Specifications, November 1, 1983.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) safety valves or the SG atmospheric relief valves (ARVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control at the Hot Shutdown Panel, and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the Hot Shutdown Panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, the shutdown transfer panel or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the required remote shutdown controls and the following instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible. The readout location for these instruments is at the Hot Shutdown Panel (HSP).

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the SG safety valves or SG ARVs; and
- RCS inventory control.

(continued)

BASES

BACKGROUND (continued)

- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators. The LCO applies to the following Remote Shutdown Instrumentation. Also provided is the total number of available channels; the number of channels required by the LCO is provided in Table 3.3.4-1.

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS
1. Neutron Flux Monitors	2
2. Wide Range RCS Temp.-T_c	1/Loop
3. Wide Range RCS Temp.-T_h	1/Loop
4. Pressurizer Pressure	1
5. Pressurizer Level	2
6. Steam Generator Pressure	1/SG
7. Steam Generator Level	1/SG
8. Auxiliary Feedwater Flow Rate to Steam Generator	2/SG
9. Condensate Storage Tank Level	2
10. Charging Pump to CVCS Charging and RCP Seals - Flow Indication	1

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3. The criteria governing the design and specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

The Remote Shutdown System satisfies Criterion 4 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The readout location for these instruments is at the Hot Shutdown Panel (HSP). The instrumentation required is listed in Table 3.3.4-1 in the accompanying LCO.

A Function of a Remote Shutdown System in Table 3.3.4-1 is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE.The required controls are specified in Reference 2.

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room. This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1 and for each required Hot Shutdown Panel (HSP) control. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function. When the Required Channels in Table 3.3.4-1 are specified (e.g., on a per SG, per loop, etc. basis), then the Condition may be entered separately for each SG, loop, etc. as appropriate.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System in Table 3.3.4-1 or one or more required HSP controls are inoperable.

(continued)

BASES

ACTIONS

A.1 (continued)

The Required Action is to restore the required Function and required HSP controls to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. 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.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized. With the exception of the charging pump to CVCS and RCP seals flow indication, all instruments listed in Table 3.3.4-1 are normally energized. The Frequency of 31 days is based upon operating experience which demonstrates that channel failure is rare.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System HSP power and control circuit and transfer switch performs the intended function. This verification is performed from the Hot Shutdown Panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels usually pass the Surveillance test when performed at the 18 month Frequency.

SR 3.3.4.3

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. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD) sensors is accomplished by an in-place cross calibration that compares the other sensing elements with the recently installed sensing element. The Frequency of 18 months is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 3 and 19.
2. FSAR Section 7.4

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs in the 6.9kv bus. Each unit has a designated Preferred offsite power source and a designated Alternate offsite power source. The Preferred offsite power source normally energizes the 6.9kV Class 1E buses. If the Preferred offsite power source is lost, the 6.9kV Class 1E buses are automatically energized from the Alternate offsite power source. If the transfer fails, or if the Alternate offsite power source is not available, the diesel generators are started to energize the 6.9kV Class 1E buses.

For each unit, the undervoltage protection system, leading to the start of the diesel generators on loss of power, consists of the following functional groups:

- Preferred offsite source undervoltage,
- Alternate offsite source undervoltage,
- 6.9kV Class 1E buses loss of voltage,
- 480V Class 1E buses low grid undervoltage,
- 6.9 kV Class 1E buses degraded voltage, and
- 480V Class 1E buses degraded voltage.

Each of the above groups consists of two sensing relays per bus that provide input to two-out-of two logic. The LOP start actuation logic is described in FSAR, Section 8.3 (Ref. 1). In general, sensing relays for each train feed a network of logic and actuation relays for their respective trains. The network of logic and actuation relays actuate the offsite power source breakers and generator start signals as described in the FSAR.

Trip Setpoints and Allowable Values

The Trip Setpoints and associated time delays used in the relays are consistent with the analytical limits presented in FSAR, Chapter 15 (Ref. 2). The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account.

(continued)

BASES

BACKGROUND (continued)

The actual nominal Trip Setpoint entered into the relays is within the allowable value or more conservative than that required by the Allowable Value. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE.

Setpoints adjusted in accordance with the Allowable Value ensure that the consequences of accidents will be acceptable, provided the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values are specified in Table 3.3.5-1 for each Function in SR 3.3.5.3. The Trip Setpoints are listed in Table B 3.3.5-1. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a Trip Setpoint less conservative than the nominal Trip Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value specified takes into account the instrument uncertainties appropriate to the trip function. These uncertainties are defined in the relay setting calculations.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power or degraded power system. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power with or without a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment include the appropriate DG loading and sequencing delay. The LOP DG start instrumentation channels satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that two channels per bus of the loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. Two trains of Automatic Actuation Logic and Actuation Relays shall also be OPERABLE in MODES 1, 2, 3 and 4. In MODES 5 and 6, there is sufficient time available such that manual loading of the DGs started by LOP DG start automatic logic, i.e. bus undervoltage signal, is acceptable. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES.

A Note has been added that limits the applicability of the 6.9 kV Preferred Offsite Voltage Source Undervoltage function to those times when the associated source breaker is closed. When this breaker is open, the Preferred Offsite Voltage Source is not supplying power to the unit; thus, it will not cause an undervoltage DG start signal and the preferred source undervoltage functions are not required to be operable.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

(continued)

BASES

ACTIONS (continued)

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to one or more LOP DG start Functions with one channel per bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are configured to provide a one-out-of-one logic to trip the incoming offsite power and initiate the LOP DG start logic.

The specified Completion Time is reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

A note has been added to clarify that this Condition is not applicable to the Automatic Actuation Logic and Actuation Relay function. This function is addressed by Condition F.

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

Condition B applies when both loss of voltage channels on the Preferred Offsite Voltage Source bus are inoperable.

Required Action B.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Alternatively, Required Actions B.2.1 and B.2.2 can be completed. Action B.2.1 requires the Preferred Offsite Voltage Source bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, “AC Sources - Operating,” be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the preferred offsite power source) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring

(continued)

BASES

ACTIONS

B.1, B.2.1, and B.2.2 (continued)

during this interval. Action B.2.2 requires that the Preferred Offsite Voltage Source Breaker be opened within 6 hours. Opening this breaker separates the preferred offsite power source from the Class 1E system and thereby eliminates the need for any undervoltage monitoring and eliminates any potential impact resulting from having an unmonitored power source connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval.

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

Condition C applies when both loss of voltage channels on the Alternate Offsite Voltage Source bus are inoperable.

Required Action C.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Alternatively, Required Actions C.2.1 and C.2.2 can be completed. Action C.2.1 requires the Alternate Offsite Voltage Source bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, “AC Sources - Operating,” be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the alternate offsite power source) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. Action C.2.2 requires that the Alternate Offsite Voltage Source Breaker be opened within 6 hours. Opening this breaker separates the alternate offsite power source from the Class 1E system and thereby eliminates the need for any undervoltage monitoring and eliminates any potential impact resulting from having an unmonitored power source connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval.

D.1 and D.2

Condition D applies when both loss of voltage channels on the 6.9 kV safeguards bus are inoperable.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

Required Action D.1 requires restoring one channel to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Alternatively, Required Actions D.2 can be completed. Action D.2 requires the affected 6.9 kV bus be declared inoperable and the appropriate condition(s) specified in LCO 3.8.9, “Electrical Power Systems, Distribution Systems - Operating,” be entered within one hour. This requires that the additional Required Actions associated with an inoperable monitored function (the affected 6.9kV bus) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. The affected bus remains available to support required components although automatically powering the bus from the associated diesel generator may not occur on bus undervoltage.

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

Condition E applies when two channels per bus with one or more degraded voltage or low grid undervoltage functions inoperable.

Required Action E.1 requires restoring one channel per bus to OPERABLE status within one hour. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

Alternatively, Required Actions E.2.1 and E.2.2 can be completed. Action E.2.1 requires that the offsite power sources be declared inoperable and the appropriate condition(s) specified in LCO 3.8.1, “AC Sources - Operating,” be entered within one hour. This requires that the additional Required Actions associated with the inoperable monitored functions (the offsite power sources) be taken. The 1 hour completion time allows time to repair at least one channel and takes into account the low probability of an event requiring an LOP start occurring during this interval. Action E.2.2 requires that the offsite power source breakers be opened within 6 hours. Opening these breakers separates the offsite power sources from the Class 1E system and thereby eliminates the need for any monitoring of degraded voltage or low grid undervoltage for the offsite power sources and eliminates any potential impact resulting from having unmonitored offsite power sources connected to the Class 1E distribution system. The 6 hour completion time allows additional time to repair at least one inoperable channel and takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

BASES

ACTIONS (continued)

F.1

Condition F applies when one or more trains of Automatic Actuation Logic and Actuation Relay function are inoperable.

Required Action F.1 requires restoring the inoperable train(s) to OPERABLE status. The 1 hour completion Time allows time to repair failures and takes into account the low probability of an event requiring LOP DG start occurring during this interval.

G.1

Condition G applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Conditions A through F are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of an ACTUATION LOGIC TEST. The LOP DG Start Automatic Actuation Logic and Actuation Relays are tested prior to entering MODE 4 when in MODE 5 for greater than or equal to 72 hours and if not performed in the previous 92 days. The Function is tested prior to entering MODE 4 to assure that the associated diesel generator is not unnecessarily started by the testing. Such unnecessary starts could be adverse to the reliability of the diesel generator. The testing verifies that the logic is OPERABLE. The Frequency of the testing is adequate. The 72 hours assures that there is sufficient time during the shutdown to perform the testing. The 92 days is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a TADOT. This test is performed prior to entry into MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in previous 92 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.5.3

SR 3.3.5.3 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of 18 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.4

SR 3.3.5.4 is the performance of the required response time verification (see also SR 3.3.2.10) every 18 months on a STAGGERED TEST BASIS on those functions with time limits provided in the Technical Requirements Manual. Each verification shall include at least one train such that both trains are verified at least once per 36 months.

REFERENCES

1. FSAR, Section 8.3.

2. FSAR, Chapter 15.

Table B 3.3.5-1 (Page 1 of 1)
LOP DG Start Instrumentation Trip Setpoint

FUNCTION	TRIP SETPOINT
Offsite Sources Undervoltage	
6.9 kV Preferred	5185 Volts
6.9 kV Alternate	5185 Volts
6.9 kV Class 1E Bus Loss of Voltage	2022 Volts
6.9 kV Class 1E Degraded Voltage	6192 Volts
480 V Class 1E Bus Low Grid Undervoltage	449.6 Volts
480 V Degraded Voltage	442.4 Volts

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Ventilation Isolation Instrumentation

BASES

BACKGROUND

Containment ventilation isolation instrumentation closes the containment isolation valves in the Containment Purge, Hydrogen Purge, and Containment Pressure Relief Systems. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Containment Pressure Relief System may be in use during reactor operation and the Containment Purge System will be in use with the reactor shutdown. The Hydrogen Purge System may only be used with the reactor shutdown and containment pressure less than 5 psig. For Modes 1 through 4, all Containment Ventilation isolation (CVI) valves are locked closed with the exception of the Containment Pressure Relief valves.

Containment ventilation isolation initiates on an automatic or manual safety injection (SI) signal through the Containment Isolation - Phase A Function, or by manual actuation of Phase A Isolation, or by manual actuation of Containment Spray. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss these modes of initiation.

One containment radiation monitor is also provided as input to the containment ventilation isolation. The monitor measures containment radiation at one location. The monitor samples the containment atmosphere and upon detection of high radiation level initiates containment ventilation isolation. Since the radiation monitor constitutes a sampling system, various components such as sample line valves, and sample pumps are required to support monitor OPERABILITY.

The Containment Purge, Hydrogen Purge, and Containment Pressure Relief systems each have inner and outer containment isolation valves on their containment penetration flow paths. A high radiation signal initiates containment ventilation isolation, which closes both inner and outer containment isolation valves in the Containment Purge, Hydrogen Purge, and Containment Pressure Relief Systems. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety analyses for LOCA assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event. Containment pressure relief is assumed to be isolated within 5 seconds of Pressurizer Pressure Low for LOCA. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 (Ref. 1) limits.

There is no credit taken for containment isolation by the radiation monitor in the accident analyses. There is no credit taken for containment isolation for a fuel handling accident.

The containment ventilation isolation instrumentation satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation

Containment Ventilation Isolation is manually initiated when the Phase “A” isolation function or the containment spray function is manually initiated. Refer to the Bases for LCO 3.3.2, “ESFAS Instrumentation,” Function 3.a.1 and 2.a, respectively, for applicability, required channels and surveillance requirements.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b, SI, and ESFAS Function 3.a.(2), Containment Phase A Isolation. The applicable MODES and specified conditions for the containment ventilation isolation portion of these Functions are different and less restrictive than those for their Phase A isolation and SI roles. If one or more of the SI or Phase A isolation Functions becomes inoperable in such a manner that only the Containment Ventilation Isolation Function is affected, the Conditions applicable to their SI and Phase A isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Ventilation Isolation Functions specify sufficient compensatory measures for this case.

(continued)

BASES

LCO (continued)

3. Containment Radiation

The LCO specifies one required radiation monitoring channel to ensure that the radiation monitoring instrumentation necessary to initiate Containment Ventilation Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, and sample pump operation, as well as detector OPERABILITY. These supporting features are necessary for a containment radiation trip to occur under the conditions assumed by the safety analyses. The Trip Setpoint for this Function is selected to satisfy the Gaseous Effluent Dose Rate requirements in Part I of the Offsite Dose Calculation Manual (ODCM).

4. Containment Isolation-Phase A

Refer to LCO 3.3.2, Function 3.a., for all initiating Functions and requirements. The operator can initiate Containment Ventilation Isolation at any time by using either of two Containment Isolation Phase A manual switches in the control room. Either switch actuates both trains. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

This function's requirements encompass the requirement to test the manual initiation which ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

APPLICABILITY

The Manual Initiation, Automatic Actuation Logic and Actuation Relays, Containment Isolation - Phase A, and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4, and, for the radiation function, during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. Under these conditions, the potential exists for an accident that could release fission product radioactivity into containment. Therefore, the containment ventilation isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without fuel handling in progress, the containment ventilation isolation instrumentation need not be OPERABLE since the

(continued)

BASES

APPLICABILITY (continued)

potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

The Applicability for the containment ventilation isolation on the ESFAS Containment Isolation - Phase A Function is specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for a discussion of the Containment Isolation - Phase A Function Applicability.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification.

A Note has been 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 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to failure of the radiation monitor channel. Since the containment radiation monitor measures the containment atmosphere and provides an actuation signal, failure of the channel results in the loss of the radiation monitoring Function. Consequently, the channel must be restored to OPERABLE status. The 4 hours allowed to restore the affected channel is justified by the low likelihood of events occurring during this interval.

B.1

Condition B applies to all Containment Ventilation Isolation Automatic Actuation Logic and Actuation relays and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for this Function. Condition B also applies to the radiation monitoring channel if the required action and completion times of Condition A are not met.

(continued)

BASES

ACTIONS (continued)

B.1 (continued)

If a train is inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

A Note is added to allow the containment pressure relief valves to be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM, for Required Action and associated Completion Time of Condition A not met.

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

C.1 and C.2

Condition C applies to the inability to restore the radiation monitoring channel to OPERABLE status in the time allowed for Required Action A.1. If the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain containment ventilation isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.4, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. A note allows the containment pressure relief valves to be opened in compliance with gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. The Completion Time for these Required Actions is Immediately.

A Note states that Condition C is applicable during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Ventilation Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1 (continued)

The Frequency is based on 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 the LCO required channels.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is performed every 92 days on a STAGGERED TEST BASIS. The Surveillance interval is justified in Reference 4.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The Surveillance interval is justified in Reference 4.

SR 3.3.6.4

A COT is performed every 92 days on each required channel to ensure the entire channel will perform the intended Function. The Frequency is based on the staff recommendation for increasing the availability of radiation monitors according to NUREG-1366 (Ref. 2). This test verifies the capability of the instrumentation to provide the containment purge and exhaust system isolation. The setpoint shall be left consistent with the current calibration procedure tolerance.

SR 3.3.6.5

SR 3.3.6.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.5 (continued)

verified in one of two ways. Actuation equipment that may be operated in thedesign mitigation mode is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing contacts operated by the slave relay. This test is performed every 92 days. The Frequency is acceptable based on instrument reliability and industry operating experience.

For ESFAS slave relays and auxiliary relays which are Westinghouse type AR relays, the SLAVE RELAY TEST is performed every 18 months. The Frequency is based on the slave relay reliability assessment presented in Reference 3. This reliability assessment is relay specific and applies only to Westinghouse type AR relays with AC coils. Note that, for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in Reference 3.

SR 3.3.6.6

Not Used.

SR 3.3.6.7

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 100.11.

2. NUREG-1366, July 22, 1993.

3. WCAP-13877-P-A, Revision 2, August 2000.

4. WCAP-15376-P-A, Revision 2, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

BASES

BACKGROUND

The CREFS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the control room is pressurized by the Control Room A/C System. Upon receipt of an actuation signal, the CREFS initiates filtered ventilation and continues pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Emergency Filtration System."

The actuation instrumentation consists of redundant radiation monitors in each of the two air intakes (one for each train in each intake). A high radiation signal from any of these detectors will initiate both trains of the CREFS. The control room operator can also initiate CREFS trains by a two train common manual switch in the control room. The CREFS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CREFS acts to terminate the supply of unfiltered outside air to the control room, initiate filtration, and maintain the control room pressurization. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel [Ref. 1].

In MODES 1, 2, 3, and 4, the radiation monitor actuation of the CREFS is a backup for the SI signal actuation. This ensures initiation of the CREFS during a loss of coolant accident including rod ejection accidents, or steam generator tube rupture accidents.

The radiation monitor actuation of the CREFS in MODES 5 and 6, during movement of irradiated fuel assemblies, is the primary means to ensure control room habitability in the event of a fuel handling or waste gas decay tank rupture accident. Since the Control room is common to both Unit 1 and Unit 2, the CREFS actuation instrumentation is required for the conditions and modes of both units.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CREFS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREFS is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate the CREFS at any time by using a common two-train switch module in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals. Separate reset switches are provided for Train A and for Train B CREFS.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one contact in the common switch and the interconnecting wiring to the actuation logic cabinet.

The surveillance testing of the manual initiation functions also tests the circuitry and relays that are actuated by the SI slave relays.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays consist of a single radiation monitor output logic relay for each train

3. Control Room Radiation

The LCO specifies two required Control Room Air Intake Radiation Monitors per intake to ensure that the radiation monitoring instrumentation necessary to initiate the CREFS remains OPERABLE.

Each Control room intake is a separate function because they are physically separated and each has redundant monitors for CREFS initiation.

(continued)

BASES

LCO

3. Control Room Radiation (continued)

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

4. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, 5, 6 and movement of irradiated fuel assemblies. The Functions must also be OPERABLE in MODES 5 and 6 when required for a waste gas decay tank rupture accident, to ensure a habitable environment for the control room operators.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/ train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1 and A.2

Condition A applies to the actuation logic train Function of the CREFS, the radiation monitor channel Functions, and the manual channel Functions.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

If one train is inoperable, or one radiation monitor channel is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. If the channel/train cannot be restored to OPERABLE status, the affected CREFS train must be placed in the emergency recirculation mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

Alternatively, the makeup air supply fan from the affected air intake may be secured. This action is modified by a note that states it is applicable only to the control room radiation monitors. This action ensures that in the event of a radiological accident, the control room will not be supplied air through an unmonitored air intake.

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

Condition B applies to the failure of two CREFS actuation trains, two radiation monitor channels, or two manual channels. The first Required Action is to place one CREFS train in the emergency recirculation mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.10 must also be entered for one CREFS train made inoperable by inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

Alternatively, as described in the Note, if the affected channels are both of the north air intake radiation monitors or both of the south air intake radiation monitors, the control room makeup supply fan from the affected air intake is required to be immediately secured.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met during MODE 5 or 6 or when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies and CORE ALTERATIONS must be suspended immediately to reduce the risk of accidents that would require CREFS actuation

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CREFS Actuation Functions.

SR 3.3.7.1

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

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

The Frequency is based on 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 the LCO required channels.

SR 3.3.7.2

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREFS actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2 (continued)

experience. The COT surveillance of the control room air intake monitors verifies the contacts and circuitry between the monitors and the CREFS actuation circuits, and thereby satisfies the COT for Automatic Actuation Logic and Actuation Relays.

SR 3.3.7.3

Not Used.

SR 3.3.7.4

Not Used.

SR 3.3.7.5

Not Used.

SR 3.3.7.6

SR 3.3.7.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 18 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device.

The test also includes trip devices that provide actuation signals directly to the Solid State Protection System, bypassing the analog process control equipment. The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

SR 3.3.7.7

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

(continued)

BASES (continued)

REFERENCES	1.	FSAR Section 6.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses and includes an allowance of 1.8% flow for measurement uncertainties. Flow rate indications from the plant computer or RCS flow rate indicators are averaged to come up with a value for comparison to the limit during shiftly surveillances. A lower RCS flow will cause the DNB limits to be approached. After each refueling, the elbow tap differential pressure transmitters are normalized to the precision RCS flow measurement. The uncertainty associated with the RCS flow measurement (1.8%) is based on the use of the feedwater venturis and precision instrumentation which has been calibrated within 90 days of performing the calorimetric flow measurement.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Operation for significant periods of time outside the limits on RCS flow, pressurizer pressure and average temperature increases the likelihood of a fuel cladding failure if a DNB limited event were to occur.

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criterion. The transients analyzed for include loss of coolant flow events and dropped rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.7, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and the RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty. These uncertainties are based on the use of control board indications.

The RCS DNB parameters satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. These variables are considered in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

RCS total flow rate contains a measurement error of 1.8% based on performing a precision heat balance and using the result to normalize the RCS flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner.

Any fouling that might significantly bias the flow rate measurement can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling. CPSES also uses the Transit Time Flow Meter (TTFM) to measure the volumetric RCS hot leg flow rate. The use of the TTFM results in an RCS flow measurement which is more accurate and less sensitive to RCS fluid conditions than other methods.

The numerical values for pressure, temperature, and flow rate specified in the COLR have been adjusted for instrument error.

(continued)

BASES

LCO (continued)

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure 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 that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and reduce the potential for violation of the accident analysis limits.

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

B.1

This condition is modified by a note that states that this condition is only applicable prior to exceeding 85% RTP after a refueling outage. This

(continued)

BASES

ACTIONS

B.1 (continued)

applicability is consistent with the required performance of SR 3.4.1.4. The purpose of this condition is to provide instructions should SR 3.4.1.4 not be completed satisfactorily during the initial power ascension following a refueling outage. If, or any reason, SR 3.4.1.4 is performed during a mid-cycle outage, and verification of the RCS flow can not be verified, Condition A should be entered.

The precision RCS flow measurement is performed following each refueling outage, or other outage in which an activity was performed that could affect the RCS flow indication. The precision flow measurement is required to be performed prior to exceeding 85% RTP, and is predicated upon the verification that:

- measured RCS flow based on elbow tap differential pressure measurement prior to Mode 1 is within 20% of the expected RCS flow;
- the power-dependent enthalpy rise peaking factor ($F_{\Delta H}$) is within its limits; and
- the trip setpoint of the power range neutron flux - high reactor trip function is maintained at a reduced setpoint (typically 90% RTP) until the RCS flow has been verified to be within analyzed values.

Under these conditions, analyses have been performed to demonstrate that operation for an indefinite period of time is permissible. It is anticipated that the time of operation in this condition will be limited to the time required to re-calibrate and re-measure the flow, or, if necessary, to revise the safety analyses to support a lower RCS flow.

C.1

If Required Action A.1 or B.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

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

SR 3.4.1.2

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

SR 3.4.1.3

The 12 hour Surveillance Frequency for the indicated RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions. The indication for this parameter indicates in percent (%). The value in % that will assure compliance with the minimum total flow limit in the SR is determined based on the measured RCS total flow from SR 3.4.1.4. Following each refueling outage and prior to the completion of SR 3.4.1.4, the value in % used to assure compliance with the minimum RCS total flow is based upon the measured RCS total flow (SR 3.4.1.4) from the previous operating cycle or an alternate measurement and assessment of actual RCS total flow.

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 18 months (after each refueling) allows the installed RCS flow instrumentation to be normalized and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.4 (continued)

The Frequency of 18 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until after exceeding 85% RTP after each refueling outage. Using precision instrumentation with multiple indications, the stated RCS flow accuracy may be attained at power levels significantly below 85% RTP, as described in the uncertainty analyses. Requiring the precision flow measurement to be performed prior to 85% RTP allows for a single testing plateau to be used to perform the RCS flow measurement and various other tests described in Section 3.2. Procedures require that the THERMAL POWER, available instrumentation, and calibration intervals be sufficient to ensure that the stated RCS flow accuracy is attained. For feedwater pressure and temperature, the main steam pressure, and feedwater flow differential pressure instruments are calibrated within 90 days of performing the calorimetric flow measurement.

REFERENCES

1. FSAR, Section 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures greater than or equal to the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) with an operating loop temperature less than a small band below the 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.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $K_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $K_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 551°F every 12 hours.

The SR to verify operating RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.

REFERENCES

1. FSAR, Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

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

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature.

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

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

(continued)

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the 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 criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

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. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (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. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The two elements of this LCO are:

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

b. Limits on the rate of change of temperature.

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

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

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

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

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

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

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

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

(continued)

BASES

APPLICABILITY (continued)

Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

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

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

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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.

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

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

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

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified 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 in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

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

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

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. Not used.

2. 10 CFR 50, Appendix G.

3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

4. ASTM E 185-82, July 1982.

5. 10 CFR 50, Appendix H.

6. Regulatory Guide 1.99, Revision 2, May 1988.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

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

The secondary functions of the RCS include:

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

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

c. Carrying the soluble neutron poison, boric acid;

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

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

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident 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 RCS loops in service.

All of the accident/safety analyses performed at full rated thermal power assume that all four RCS loops are in operation as an initial condition. Some accident/safety analyses have been performed at zero power conditions assuming only two RCS loops are in operation to conservatively bound lower

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

modes of operation. The uncontrolled RCCA (Bank) withdrawal from subcritical event is included in this category. While all accident/safety analyses performed at full rated thermal power assume that all the RCS loops are in operation, selected events examine the effects resulting from a loss of RCP operation. These include the complete and partial loss of forced RCS flow, RCP rotor seizure, and RCP shaft break events. For each of these events, it is demonstrated that all the applicable safety criteria are satisfied. For the remaining accident/safety analyses, operation of all four RCS loops during the transient up to the time of reactor trip is assumed thereby ensuring that all the applicable acceptance criteria are satisfied. Those transients analyzed beyond the time of reactor trip were examined both with and without a subsequent loss of offsite power to ensure the scenario that was most limiting with respect to the event acceptance criteria was analyzed.

The plant is designed to operate with all RCS loops in operation SAFETY to maintain DNBR above the limit value, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required to be in operation at power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

(continued)

BASES

APPLICABILITY (continued)

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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. FSAR, Section 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops - MODE 3

BASES

BACKGROUND	In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid. The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.
APPLICABLE SAFETY ANALYSES	Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM housing. Therefore, in MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when APPLICABLE the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses. Failure to provide decay 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

When the Rod Control System is not capable of rod withdrawal only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure that redundancy for heat removal is maintained.

The Note permits all RCPs to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are required to be performed without flow or pump noise. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause an adverse change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the 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 and because of the low probability of a failure in the remaining loop occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

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

C.1 and C.2

If the required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be in a condition incapable of rod withdrawal. The Completion Time of 1 hour to restore the required RCS loop to operation or render the Rod Control System incapable of rod withdrawal is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

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

If four RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, place the Rod Control System in a condition incapable of rod withdrawal (e.g., all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets). 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 of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. Suspending the introduction of coolant into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however

(continued)

BASES

ACTIONS

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

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 heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops. If the SG secondary side narrow range water level is <38% (Unit 1) and <10% (Unit 2), the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP 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 the required RCPs.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

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

RCS Loops - MODE 4 satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that 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 loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

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BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10ºF below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 350°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

(continued)

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";

LCO 3.4.5, "RCS Loops - MODE 3";

LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";

LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";

LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and

LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one required loop is inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200 to 350°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

B.1 and B.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, 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 RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to 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 be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥38% (Unit 1) and ≥10% (Unit 2). If the SG secondary side narrow range water level is <38% (Unit 1) and <10% (Unit 2), the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

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

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the 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 via natural circulation or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs are specified as a backup means for redundancy. Even if the SGs could not produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The capability of the RCS to achieve and maintain natural circulation is necessary when relying on the ability of the SGs to remove decay heat. The ability to pressurize and control pressure in the RCS is necessary to ensure the lowest pressure point in the RCS, at the top of the SG tubes, is maintained above the saturation pressure of the secondary side plus 50°F. (Ref. 1)

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

APPLICABLE SAFETY ANALYSES

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 RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels above 38% (Unit 1) and 10% (Unit 2) to provide an alternate method for decay heat removal via natural circulation. In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

dilution event. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Filled) satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥38% (Unit 1) and ≥10% (Unit 2). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥38% (Unit 1) and ≥10% (Unit 2). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR 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.

(continued)

BASES

LCO (continued)

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ 350°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

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

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥38% (Unit 1) and ≥10% (Unit 2).

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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels <38% (Unit 1) and <10% (Unit 2), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no 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 one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing and preserve the margin to criticality in this type of operation. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to 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 heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are $\geq$38% (Unit 1) and $\geq$10% (Unit 2) ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional 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 RHR pump. If secondary side water level is $\geq$38% (Unit1) and $\geq$10% (Unit 2) in at least two SGs, this Surveillance is not needed. 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. NRC Information Notice 95-35, “Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) 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.

In MODE 5 with loops not filled, only RHR 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 RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

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

RCS loops in MODE 5 (loops not filled) satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

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

Note 1 permits all RHR pumps to be removed from operation for $\leq$ 1 hour. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained at least 10°F below saturation temperature. 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 RHR forced flow is stopped.

(continued)

BASES

LCO (continued)

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

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System. The Applicability is modified by a Note stating that entry into MODE 5 Loops Not Filled from MODE 5 Loops Filled is not permitted while LCO 3.4.8 is not met. This Note specifies an exception to LCO 3.0.4 and would prevent draining the RCS, which would eliminate the possibility of SG heat removal, while the RHR function was degraded.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, 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 must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution, and the margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to 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 heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

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

REFERENCES

None.

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 and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the FSAR (Ref. 1) 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 pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10CFR50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 1662 cubic feet, which is equivalent to 92%, ensures that a steam bubble exists. Limiting the LCO 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 two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops.

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. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from offsite power or an

(continued)

BASES

APPLICABILITY (continued)

emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

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

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level - High Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3, with all rods fully inserted and incapable of withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand for more than one group of heaters would be unlikely in this period.

C.1 and C.2

If one required group of pressurizer heaters is inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is consistent with the safety analyses assumptions of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The pressurizer heaters used to satisfy the pressure control function are comprised of one proportional control group and three backup groups. The heater groups are normally connected to the emergency power supplies (two to each Class 1E train of emergency power) and normally operate. The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. This may also be done by energizing the heaters and measuring circuit current. The Frequency of 18 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable. The heater design and operation is consistent with the basis for an 18 month surveillance described in Section 6.6 of Ref. 3.

REFERENCES

1. FSAR, Section 15.

2. NUREG-0737, November 1980.

3. NUREG-1366, Improvements to Technical Specification Surveillance Requirements.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr at 2485 psig plus 3% accumulation, is based on postulated overpressure transient conditions resulting from a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer safety valves are then able to relieve sufficient steam to maintain the RCS pressure within 110 percent of the RCS design pressure. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves which is divided equally between the three valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures $\leq$ 320°F, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the $\pm$ 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions at the nominal operating temperature and pressure 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.

(continued)

BASES

BACKGROUND (continued)

The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Feedline break;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2485 psig), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig.

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include

(continued)

BASES

LCO (continued)

damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

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

The LCO is not applicable in MODE 4 when any RCS cold leg temperatures are ≤ 320°F or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

ACTIONS

A.1

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

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperatures ≤ 320°F within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperatures at or below 320°F, overpressure protection is provided by the LTOP System. 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 three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 15.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are nitrogen operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

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

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two PORVs, each having a relief capacity of 210,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure - High reactor trip setpoint up to and including the design step-load decrease. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical (Ref. 2). By assuming PORV manual actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. As such, this actuation is not required to mitigate these events, and the PORV automatic actuation is therefore not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE while closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render the PORV or the block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage exists when either of the following plant conditions dictate closure of the block valve to limit leakage:

a. The automatic control system cannot maintain Pressurizer pressure and level within the assumed accident analysis limits (i.e., +/-30 psig of setpoint for pressure and +/-5% of setpoint for level), or

(continued)

BASES

LCO (continued)

b. RCS identified leakage cannot be maintained less than the limits of LCO 3.4.13 without closure of the associated PORV block valve.

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODES 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

Note 1 has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valves, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

(continued)

BASES

ACTIONS (continued)

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

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not fully open. If the block valve is restored within the Completion Time of 72 hours, the power will be restored and the PORV restored to OPERABLE status. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D. The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4, 5 and 6 (with the reactor vessel head on), automatic PORV OPERABILITY may be required. See LCO 3.4.12.

E.1, E.2, E.3, and E.4

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4, 5 and 6 (with the reactor vessel head on), automatic PORV OPERABILITY may be required. See LCO 3.4.12.

F.1, and F.2

If more than one block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation. The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 5 and 6 (with the reactor vessel head on), automatic PORV OPERABILITY may be required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed. The basis for the Frequency of 92 days is the ASME Code (Ref. 3).

This SR is modified by two Notes. Note 1 modifies this SR by stating that it is not required to be performed with the block valve closed, in accordance with the Required Actions of this LCO. Opening the block valve in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable. Note 2 modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the surveillance to be performed in MODE 3 under operating temperature and pressure conditions, prior to entering MODE 1 or 2. In accordance with References 4, 5 and 6, administrative controls require this test be performed in MODES 3, 4 or 5 to adequately simulate operating temperature and pressure effects on PORV operation.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency of 18 months is based on a typical refueling cycle and industry accepted practice. The Note modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the surveillance to be performed in MODE 3 under operating temperature and pressure conditions, prior to entering MODE 1 or 2. In accordance with References 4, 5 and 6, administrative controls require this test be performed in MODES 3, 4 or 5 to adequately simulate operating temperature and pressure effects on PORV operation.

(continued)

BASES (continued)

REFERENCES

1. Regulatory Guide 1.32, February 1977.
2. FSAR, Chapter 15.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants.
4. Generic Letter 90-06, “resolution of Generic Issue 70, ‘Power-Operated Relief Valve and Block Valve Reliability,’ and generic issue 94, ‘Additional Low-Temperature Overpressure for Light-Water Reactors,’ Pursuant to 10CFR50.54(f),” June 25, 1990.
5. CPSES License Amendment 11, July 15, 1992.
6. NUREG-0797, Supplement 25, September 1992.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System acts as a backup to the reactor operators to mitigate RCS pressurization transients at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all safety injection pumps and one charging pump to be incapable of injection into the RCS and isolating the accumulators. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than two charging pumps

(continued)

BASES

BACKGROUND (continued)

for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with reduced lift settings, or two residual heat removal (RHR) suction relief valves, or one PORV and one RHR suction relief valve, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to keep from overpressurizing the RCS for the required coolant input capability.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure approaches a limit determined by the LTOP actuation logic. The LTOP System actuation logic monitors both RCS temperature and RCS pressure and determines when the PTLR limits are approached. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is processed through a function generator that calculates a pressure limit for that temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The PTLR presents the setpoints for the LTOP System. The setpoints are normally staggered so only one valve typically opens during a low temperature overpressure transient. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

RHR Suction Relief Valve Requirements

During LTOP MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot legs to the inlets of the RHR

(continued)

BASES

BACKGROUND (continued)

pumps. While these valves are open and the RHR suction valves are open, the RHR suction relief valves are exposed to the RCS and are able to relieve pressure transients in the RCS.

The RHR suction isolation valves must be open to make the RHR suction relief valves OPERABLE for RCS overpressure mitigation. The RHR suction relief valves are spring loaded, bellows type water relief valves with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves. These valves are tested in accordance with the Inservice Testing Program (IST).

RCS Vent Requirements

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

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding 320°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At about 320°F and below, overpressure prevention falls to two OPERABLE RCS relief valves or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the analyses to determine the impact of the change on the LTOP acceptance limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

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

a. Rendering all safety injection pumps and one charging pump incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Precluding start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," provide this protection.

The analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when only two charging pumps are actuated. Thus, the LCO allows only two charging pumps OPERABLE during the LTOP MODES. Since neither one RCS relief valve nor the RCS vent can handle the pressure transient from accumulator injection, when RCS temperature is low, the LCO also requires accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions. Fracture mechanics analyses establish the temperature of LTOP System Applicability at 350°F.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 5 and 6), requirements by having a maximum of two charging pumps OPERABLE and SI actuation enabled.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are 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, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The failure of one PORV is assumed to represent the worst case, single active failure.

RHR Suction Relief Valve Performance

The RHR suction relief valves do not have variable pressure and temperature lift setpoints like the PORVs. Analyses must show that one RHR suction relief valve with a setpoint at 450 ± 10% psig will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the P/T limit curve. Assuming all relief flow requirements during the limiting LTOP event, an RHR suction relief valve will maintain RCS pressure to within the valve rated lift setpoint, plus an accumulation ≤ 10% of the rated lift setpoint.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The RCS P/T limits are decreased to reflect the loss of toughness in the reactor vessel materials due to neutron embrittlement, the RHR suction relief valves must be analyzed to still accommodate the design basis transients for LTOP.

The RHR suction relief valves are assumed to function as single active failure criteria does not apply to CPSES for safety and relief valves.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.98 square inches is capable of mitigating the allowed LTOP transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, two charging pumps OPERABLE, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

This LCO requires that the LTOP System is OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires zero safety injection pumps and a maximum of two charging pumps be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized, when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The LCO is modified by a Note stating that the accumulator may be unisolated when the accumulator pressure is less than the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

(continued)

BASES

LCO (continued)

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

b. Two OPERABLE RHR suction relief valves; or

An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valves are open, its setpoint is at or between 436.5 psig and 463.5 psig, and testing has proven its ability to open at this setpoint.

c. One OPERABLE PORV and one OPERABLE RHR suction relief valve; or

d. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 2.98 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable in MODE 4, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 320°F. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above 320°F.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

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BASES

APPLICABILITY (continued)

The Applicability is modified by a Note stating that the LCO is not applicable above 320°F when at least one reactor coolant pump is in operation, pressurizer level is ≤ 92%, and the plant heatup rate is limited to 60°F in any one hour period. These conditions are included in the LTOP analysis allowing LTOP to be inoperable above 320°F.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and B.1

With one or more safety injection pumps or three charging pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

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

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1, Required Action D.2 and Required Action D.3 provide three options, one of which must be performed in the next 12 hours. By increasing the RCS temperature to > 320°F, an accumulator pressure of 693 psig cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

(continued)

BASES

ACTIONS (continued)

E.1

In MODE 4, with one required RCS relief valve inoperable, the RCS relief valve must be restored to OPERABLE status within a Completion Time of 7 days. Two RCS relief valves in any combination of the PORVS and the RHR suction relief valves are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the RCS relief valves is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 7). Thus, with one of the two RCS relief valves inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore two valves to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE RCS relief valve to protect against overpressure events.

G.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RCS relief valves are inoperable; or

b. A Required Action and associated Completion Time of Condition A, B, D, E, or F is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, D, E, or F.

The vent must be sized $\geq$2.98 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

(continued)

BASES

ACTIONS

G.1 (continued)

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of zero safety injection pumps and a maximum of two charging pumps are verified capable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out. Verification that each accumulator is isolated is only required when accumulator isolation is required as stated in Note 1 to the Applicability.

The safety injection pumps and charging pump are rendered incapable of injecting into the RCS, for example, through removing the power from the pumps by racking the breakers out under administrative control or by isolating the discharge of the pump by closed isolation valves with power removed from the operators or by a manual isolation valve secured in the closed position. Alternate methods of LTOP prevention may be employed to prevent a pump start such that a single failure will not result in an injection into the RCS. Providing pumps are rendered incapable of injecting into the RCS, they may be energized for purposes such as testing or for filling accumulators.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.4

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying its RHR suction isolation valves are open and by testing it in accordance with the Inservice Testing Program. This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO.

The RHR suction isolation valves are verified to be opened every 72 hours. The Frequency is considered adequate in view of other administrative controls such as valve status indications available to the operator in the control room that verify the RHR suction valve remains open.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.4 (continued)

The ASME Code (Ref. 8), test per Inservice Testing Program verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

SR 3.4.12.5

The RCS vent of ≥ 2.98 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked, sealed, or otherwise secured in the open position.

b. Once every 31 days for other vent paths (e.g., a valve that is locked, sealed, or otherwise secured in position). A removed pressurizer safety valve or open manway also fits this category.

Any passive vent path arrangement must only be open when required to be OPERABLE. This Surveillance is required if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.

SR 3.4.12.6

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72 hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.7

Not Used

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.8

Performance of a COT is required within 12 hours after decreasing RCS temperature to ≤ 350°F and every 31 days on each required PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the PTLR allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required.

The 12 hour allowance considers the unlikelihood of a low temperature overpressure event during this time.

A Note has been added indicating that this SR is required to be performed 12 hours after decreasing RCS cold leg temperature to ≤ 350°F. The test must be performed within 12 hours after entering the LTOP MODES.

SR 3.4.12.9

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. ASME, Boiler and Pressure Vessel Code, Section III.
4. FSAR, Chapter 15.
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. Generic Letter 90-06.
8. ASME Code for Operation and Maintenance of Nuclear Power Plants.
9. FSAR, Chapter 5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS. The reactor vessel closure head contains head adaptors. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contains ACME threads for the assembly of control rod drive mechanisms or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. Mechanical canopy seal clamp assemblies (CSCAs) may be used to contain or prevent leaks in the canopy seal.

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

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

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

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

APPLICABLE SAFETY ANALYSES

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA). 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 (SG) is one gallon per minute or increases to one gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a 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 FSAR (Ref. 3) analysis for SGTR assumes the secondary fluid is released to the atmosphere via the atmospheric relief valves on the affected steam generator. This valve is assumed to fail to close. The release continues until the reactor operators close the associated block valve. The 1 gpm primary to secondary LEAKAGE safety analysis assumption is relatively inconsequential.

The safety analysis for the SLB accident assumes the entire primary to secondary LEAKAGE is through the affected generator as an initial condition. The dose consequences resulting from the SLB accident are within the limits defined in 10 CFR 100 (Ref. 6) as described in the accident analyses (Ref. 3).

The safety analysis for RCS main loop piping for GDC-4 (Ref. 1) assumes 1 gpm unidentified leakage and monitoring per RG 1.45 (Ref. 2) are maintained (Ref. 4 and 5).

The RCS operational LEAKAGE satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

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

Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Seals and gaskets include the canopy seals downstream of ACME threaded connections and Canopy Seal Clamp Assemblies. Therefore, leakage past the canopy seal or CSCAs is not pressure boundary leakage.

b. Unidentified LEAKAGE

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

c. Identified LEAKAGE

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

d. 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.

(continued)

BASES (continued)

APPLICABILITY

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

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

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A .1

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

B.1 and B.2

If any pressure boundary LEAKAGE exists or primary to secondary LEAKAGE is not within limit, or if any unidentified or identified LEAKAGE, cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. 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 allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. 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 to be within the LCO limits ensures the integrity of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met 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). This 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 near operating pressure. The 12 hour allowance provides sufficient time to collect and process necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper 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 (T_{avg} changing by less than 5°F/hour), power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows. An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. 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. When non steady state operation precludes surveillance performance, the surveillance should be performed in a reasonable time period commensurate with the surveillance performance length, once steady state operation has been achieved, provided greater than 72 hours have elapsed since the last performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less than orequal 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, the performance criterion is not met and LCO 3.4.17, “Steam Generator Tube Integrity,” should be entered. 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. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 8).

SURVEILLANCE REQUIREMENTS

1. 10 CFR 50, Appendix A, GDC 4 and 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 15.
4. FSAR, Section 3.6B.
5. NUREG-1061, Volume 3, November 1984.
6. 10 CFR 100.
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

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line can effect the overall leakage rate determined by RCS water inventory balance of SR 3.4.13.1 and therefore may be included as part of the identified LEAKAGE, governed by LCO 3.4.13, “RCS Operational LEAKAGE”. A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

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

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

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

a. Residual Heat Removal (RHR) System;

b. Safety Injection System; and

c. Chemical and Volume Control System.

(continued)

BASES

BACKGROUND (continued)

The PIVs are listed in the Technical Requirements Manual (Ref. 6).

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

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is typically designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 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 2 of 10CFR50.36(c)(2)(ii).

LCO

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm.

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

(continued)

BASES (continued)

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 RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR 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 containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring the RCS PIV to within limits. The 72 hour Completion Time after exceeding the limit allows for the restoration of the leaking PIV to OPERABLE status. This time frame considers the time required to complete the Action and the low probability of a second valve failing during this time period.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

C.1

The inoperability of the RHR System interlock renders the RHR suction isolation valves capable of inadvertent opening at RCS pressures in excess of the RHR systems design pressure. If the RHR System interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This Action accomplishes the purpose of the function.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition greater than 150 psig.

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

Testing is to be performed every 18 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 18 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 7), and is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

In addition, testing must be performed once after the check valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

avoided. Testing must be performed within 24 hours after the check valve has been reseated (except as provided by Note 1). Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a check valve.

The leakage limit is to be met 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.

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 complementary 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 except for RHR isolation valves 8701A, 8701B, 8702A and 8702B. This exception is allowed since these RHR valves have control room position indication, inadvertent opening interlocks and a system high pressure alarm. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

Testing is not required for the RHR suction isolation valves more frequently than 18 months as these valves are motor-operated with control room position indication, inadvertent opening interlocks and system high pressure alarms.

SR 3.4.14.2

Verifying that the RHR System interlocks are OPERABLE ensures that RCS pressure will not overpressurize the RHR system. The interlock setpoint that prevents the valves from being opened is set so the actual RCS pressure must be < 442 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded and the RHR relief valves will not lift. The 18 month Frequency is based on the need to perform the Surveillance under conditions that apply during a plant outage. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

This SR is not applicable when using the RHR System suction relief valves for cold overpressure protection in accordance with SR 3.4.12.7.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.
5. NUREG-0677, May 1980.
6. Technical Requirements Manual.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants.
8. 10 CFR 50.55a(g).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

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

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

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

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

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable

(continued)

BASES

BACKGROUND (continued)

and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from air coolers. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The asymmetric loads produced by postulated breaks are the result of assumed pressure imbalance, both internal and external to the RCS. The internal asymmetric loads result from a rapid decompression that causes large transient pressure differentials across the core barrel and fuel assemblies. The external asymmetric loads result from the rapid depressurization of the annulus regions, such as the annulus between the reactor vessel and the shield wall, and cause large transient pressure differentials to act on the vessel. These differential pressure loads could damage RCS supports, core cooling equipment or core internals. This concern was first identified as Multiplant Action (MPA) D-10 and subsequently as Unresolved Safety Issue (USI) 2, “Asymmetric LOCA Loads” (Ref. 4).

The resolution of USI-2 for Westinghouse PWRs was the use of fracture mechanics technology for RCS piping >10 inches diameter (Ref. 5). This technology became known as leak-before-break (LBB). Included within the LBB methodology was the requirement to have leak detection systems capable of detecting a 1.0 gpm leak within four hours. This leakage rate is designed to ensure that adequate margins exist to detect leaks in a timely manner during normal operating conditions. The use of the LBB methodology is described in Reference 6.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

described in the FSAR (Ref. 3). Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

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

RCS leakage detection instrumentation satisfies Criterion 1 of 10CFR50.36(c)(2)(ii).

LCO

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

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the Containment Sump Level and Flow Monitoring System, particulate radioactivity monitor and either a containment air cooler condensate flow rate monitor or a gaseous radioactivity monitor provide an acceptable minimum.

APPLICABILITY

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

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

ACTIONS

A.1 and A.2

With the required Containment Sump Level and Flow Monitoring System inoperable, no other form of sampling can provide the equivalent information;

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. 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 (as defined in the Bases of SR 3.4.13.1). The 12 hour allowance provides sufficient time to collect and process necessary data after stable plant conditions are established.

Restoration of the required Containment Sump Level and Flow Monitoring System to OPERABLE status within a Completion Time of 30 days is required to regain the function 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 particulate containment atmosphere radioactivity monitoring instrumentation channel inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitor.

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 (as defined in the Bases of SR 3.4.13.1). The 12 hour allowance provides sufficient time to collect and process necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1.1, C.1.2, C.2.1 and C.2.2

With the required containment atmosphere gaseous radioactivity monitor and the required containment air cooler condensate flow rate monitor inoperable, the means of detecting leakage are the Containment Sump Level and Flow Monitoring System and the containment atmosphere particulate

(continued)

BASES

ACTIONS

C.1.1, C.1.2, C.2.1 and C.2.2 (continued)

radioactive monitor. This Condition does not provide all the required diverse means of leakage detection. With both gaseous containment atmosphere radioactivity monitoring and containment air cooler condensate flow rate monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

The followup Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

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 RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process necessary data after stable plant conditions are established.

D.1 and D.2

If a Required Action of Condition A, B or C cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

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

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1 (continued)

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 COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3, SR 3.4.15.4, and SR 3.4.15.5

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

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. Regulatory Guide 1.45.
3. FSAR, Section 5.2.
4. NUREG-609, “Asymmetric Blowdown Loads on PWR Primary Systems,” 1981.
5. Generic Letter 84-04, “Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops.”
6. FSAR, Section 3.6B.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the Exclusion Area boundary can receive for 2 hours following an accident, or at the Low Population Zone outer boundary for the radiological release duration, is specified in 10 CFR 100.11 (Ref. 1). Doses to the Control Room operators must be limited per GDC 19. The limits on specific activity ensure that the appropriately limited 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) or a main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and Control Room doses meet the appropriate acceptance criteria in the Standard Review Plan. The limits in the LCO are specific to CPSES due to the implementation of the alternate steam generator tube repair criteria.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting offsite and Control Room doses meet the appropriate Standard Review Plan acceptance criteria following a SGTR or a MSLB accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at, or more conservative than, the LCO limit[1] and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm. The MSLB safety analysis (Ref. 3) assumes the specific activity of the reactor coolant at, or more conservative than, the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 27.8 gpm[2] in the affected steam generator and 450 gpm combined in the unaffected steam generators.

(continued)

[1] The referenced safety analysis reports the doses for the SGTR assuming DEI-131 to be 1.0 μCi/gm. The doses reported using this value have been shown to be conservative relative to those that would be calculated using a DEI-131 value of 0.45 μCi/gm.

[2] To obtain the maximum benefit from the steam generator alternate repair criteria, the MSLB radiological consequences analysis assumes a leak rate to the faulted steam generator during the accident that results in calculated consequences approaching a small fraction (10%) of the 10 CFR 100 guideline values for the accident initiated spike. This leak rate provides a maximum primary -to-secondary leak rate limit against which the predicted end-of-cycle leakage is compared.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis for both accidents assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity."

The analysis for the MSLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses are used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

Each of the above analyses must consider two cases of reactor coolant specific activity. One case assumes specific activity at 0.45 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases, by a factor of 500 or 335, the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a MSLB or SGTR, respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas specific activity is assumed to be the equivalent of 1% fuel defects which corresponds to 715 μCi/gm DOSE EQUIVALENT XE-133.

These analyses also assume a loss of offsite power at the same time as the SGTR or the MSLB event. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature N-16 signal. The MSLB causes a reduction in reactor coolant temperature and pressure. The temperature decrease causes an increase in reactor power. The power increase will trip the reactor on high neutron flux or overpower N-16. The pressure decrease will initiate a reactor trip on either low pressurizer pressure or the safety injection signal initiated by low pressurizer pressure, low steam generator pressure, or high containment pressure.

For the SGTR and the MSLB, the coincident loss of offsite power causes the steam dump valves to close to protect the condenser. For the SGTR, a rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG atmospheric relief valves and the main steam safety valves. A failure to close of the atmospheric relief valve on the affected SG is also assumed. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the RHR system is placed in service. For the MSLB, an uncontrolled (i.e, released to atmosphere) blowdown of only one steam generator is assumed. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the RHR system is placed in service. Radioactively contaminated steam is released to the atmosphere through the faulted SG as well as the intact SGs

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

assuming the primary to secondary leak rates shown above.

The applicable safety analysis shows the radiological consequences of either an SGTR or an MSLB accident are within a small fraction of the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 60.0 μCi/gm DOSE EQUIVALENT I-131 for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The iodine specific activity in the reactor coolant is limited to 0.45 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 500 μCi/gm DOSE EQUIVALENT XE-133, as contained in SR 3.4.16.2 and SR 3.4.16.1 respectively. The limits on specific activity ensure that offsite and Control Room doses will meet the appropriate Standard Review Plan acceptance criteria.

The SGTR accident analysis (Ref. 2) and the MSLB accident analysis (Ref. 3) show that the calculated 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 or MSLB, lead to site boundary doses that exceed the SRP acceptance criteria.

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of an SGTR and an MSLB to within the SRP acceptance criteria.

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, monitoring of RCS specific activity is not required.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is $\leq$ 60.0 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is acceptable since it is expected that, if there were no iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a MSLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

With the DOSE EQUIVALENT XE-133 in excess of the allowed limit, DOSE EQUIVALENT XE-133 must be restored to within limits within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a MSLB or SGTR occurring during this time period.

A NOTE permits the use of the provisions of LCO 3.04.c. This allowance permits entry into the applicable MODE(S), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

C.1 and C.2

If the Required Action and the associated Completion Time of Condition A or B is not met or if the DOSE EQUIVALENT I-131 is > 60.0 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. While basically a quantitative measure of radionuclides with half lives longer than 10 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in noble gas 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 7 day Frequency considers the unlikelihood of a gross fuel failure during the time.

If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 in Specification 1.1, “Definitions,” is not detected, it should be assumed to be present at the minimum detectable activity.

The NOTE modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change $\geq$ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

The NOTE modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

SR 3.4.16.3

DELETED

(continued)

BASES (continued)

REFERENCES

1.) 10 CFR 100.11, 1973.

2.) FSAR, Section 15.6.3.

3.) FSAR, Section 15.1.5

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 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).

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BASES (continued)

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. However, the radiological dose consequence analysis for SGTR assumes the condenser is not available, and that the Atmospheric Relief Valve on the affected (ruptured) SG opens following the reactor trip / turbine trip and fails to close, thereby releasing the radioactivity directly to the atmosphere.

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 (or repaired for Unit 1 D4 SGs only) in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is repaired (Unit 1 D4 SGs only) or removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged (or repaired for Unit 1 D4 SGs only), 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 and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at

(continued)

BASES

LCO (continued)

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.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, “The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.” Tube collapse is defined as, “For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero.” The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term “significant” is defined as “An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established.” For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

(continued)

BASES

LCO (continued)

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, except for specific types of degradation at specific locations where the NRC has approved greater accident induced leakage (i.e., Specification 5.5.9.1; “Unit 1 model D4 Steam Generator (SG) Program”). 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.

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 (or repaired for Unit 1 D4 SGs only) in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 (or repaired for Unit 1 D4 SGs only) has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

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 (or repaired for Unit 1 D4 SGs only) prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1 (continued)

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 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is repaired (Unit 1 D4 SGs only) or 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.2 (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 (or repaired for Unit 1 D4 SGs only) 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 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are 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.

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

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator 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 (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

The motor operated isolation valves are required to be open with power removed in MODE 3 above 1000 psig to satisfy BTP ICSB-18 [Ref. 1] for small break LOCAs. They are required to be open with power removed in MODES 1 and 2 for large break LOCA.

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur

(continued)

BASES

BACKGROUND (continued)

following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 2). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay 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 primarily by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and centrifugal charging pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the centrifugal charging pumps become solely responsible for terminating the temperature increase.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 3) 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; and

d. Core is maintained in a coolable geometry.

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

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. For small breaks, an increase in water volume may be either a peak clad temperature penalty or benefit depending on the transient characteristics. Depending on the NRC-approved methodology used to analyze large breaks, an increase in water volume may be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis makes a conservative assumption with respect to ignoring or taking credit for line water volume from the accumulator to the check valve. The safety analysis assumes values of 6119 gallons and 6597 gallons.

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure (603 psia), since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit (693 psia) prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

To allow for instrument inaccuracy, control room indicated values of 623 psig and 644 psig are specified and used in surveillance.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 2 and 4).

The accumulators satisfy Criteria 2 and 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 3) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above a nominal RCS pressure of 1000 psig, 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 > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 3) limit of 2200°F.

(continued)

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. Accumulator isolation is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature, as allowed by the P/T curves provided in the PTLR. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, the ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analyses demonstrate that the accumulators do not discharge following a large main steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 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 accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified - WCAP-15049, Rev. 1 (Ref. 5).

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and RCS pressure reduced to ≤1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

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

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators 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 not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

Each accumulator is equipped with two level and two pressure channels. One channel of each is designated the primary channel and used for this surveillance except when declared inoperable. The second channel is used to perform channel checks and as backup to the primary channel. Surveillances are routinely performed on both channels.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 and SR 3.5.1.3 (continued)

Control Board indication may be used in the surveillances of the required indicated water volume. To allow for a 5% instrument inaccuracy and a 1% tank tolerance, control room indicated values of 39% and 61% are conservative and may be used in surveillance. Other means of surveillance which consider measurement uncertainty may also be used.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage. Sampling the affected accumulator within 6 hours after a 1% volume increase (101 gallons) will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), and the RWST has not been diluted since verifying that its boron concentration satisfies SR 3.5.4.3, because the water contained in the RWST is nominally within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 6).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the RCS pressure is > 1000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is ≤ 1000 psig.

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BASES (continued)

REFERENCES

1. BTP ICSB-18 (Rev. 2, July 1981) "Application of the single failure criterion to manually controlled electrically operated valves.
2. FSAR, Chapter 6.
3. 10 CFR 50.46.
4. FSAR, Chapter 15.
5. WCAP-15049-A, Rev. 1, April 1999.
6. NUREG-1366, December 1992.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

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

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for cold leg recirculation. After several hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The ECCS consists of three separate subsystems: centrifugal charging (high head), safety injection (SI) (intermediate head), and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the centrifugal charging pumps, the RHR pumps, heat exchangers, and

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BASES

BACKGROUND (background)

the SI pumps. Each of the three subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Separate piping supplies each subsystem and each train within the subsystem. The discharge from the centrifugal charging pumps combines in a common header and then divides again into four supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the SI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Throttle valves are set to balance the flow to the RCS. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs. The throttle valves also protect the SI pumps and centrifugal charging pumps from exceeding runout flow rates.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the centrifugal charging pumps supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps then supply the other ECCS pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation alternates injection between the hot and cold legs.

The centrifugal charging subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

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

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BASES

BACKGROUND (background)

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start after a one second sequencer delay in the programmed time sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

Each ECCS pump is provided with normally open miniflow lines for pump protection. The RHR miniflow isolation valves close on flow to the RCS and have a time delay to prevent them from closing until the RHR pumps are up to speed and capable of delivering fluid to the RCS. The SI pump minflow isolation valves are closed manually from the control room prior to transfer from injection to recirculation. The Charging Pump miniflow isolation valves close on receipt of a safety injection signal and alternate minflow isolation valves open.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

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

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

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

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

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The centrifugal charging pumps and SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the centrifugal charging pumps. The SGTR and MSLB events also credit the centrifugal charging pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one RHR pump (both EDG trains are assumed to operate due to requirements for modeling full active containment heat removal system operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the centrifugal charging and SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For smaller LOCAs, the centrifugal charging pump delivers sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

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

In MODES 1, 2, and 3, an ECCS train consists of a centrifugal charging subsystem, an SI subsystem, and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and initiating semi-automatic switchover of suction to the containment sump.

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

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

As indicated in Note 1, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room and a single active failure (Ref. 7) is not assumed coincident with this testing. Therefore the ECCS trains are considered Operable during this isolation.

As indicated in Note 2, operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. The note allows this condition up to 375°F to ensure conditions are above the LTOP arming temperature. LCO 3.4.12 requires that certain pumps be rendered incapable of injecting at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS 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

(continued)

BASES

APPLICABILITY (continued)

requirements in the lower MODES. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

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

ACTIONS

A.1

With one centrifugal charging pump (CCP) inoperable, the inoperable CCP must be returned to OPERABLE status within 7 days. The 7 day allowed outage time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program and is a reasonable time for the repair of a CCP.

B.1

With one or more trains inoperable, for reasons other than one inoperable centrifugal charging pump, and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

100% of the ECCS flow equivalent to a single OPERABLE ECCS train is considered available if the following conditions are met: 1) There must be one fully OPERABLE centrifugal charging pump, one fully OPERABLE safety injection pump and one fully OPERABLE RHR pump with associated heat exchanger at a minimum. 2) The flow paths associated with each pump and heat exchanger for which credit is being taken must be OPERABLE in

(continued)

BASES

ACTIONS

B.1 (continued)

the injection and recirculation flow paths. 3) ECCS system alignment, with the exception of isolation valves for inoperable pumps and heat exchangers must be normal. 4) All automatic functions and interlocks must be OPERABLE for the components for which credit is being taken. 5) All support systems for the pumps and heat exchangers for which credit is being taken are OPERABLE. 6) The combination of components must be such that a transition from cold leg to hot leg recirculation can be accomplished.

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

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

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 6 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

C.1 and C.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power by a control board switch in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in References 6 and 7, that can disable the function of both ECCS trains and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely. As noted in LCO Note 1, both Safety Injection pump flow paths may each be isolated for two hours in MODE 3 by closure of one or more of these valves to perform pressure isolation valve testing.

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

Venting of the ECCS pump casing and accessible discharge piping high points prior to entering MODE 3 and following any maintenance or operations activity which drains portions of the system, ensures the system is full of water and will perform properly (i.e., allows injecting the full ECCS capacity into the RCS on demand).

The CCP design and attached piping configuration allow the CCP to vent the accumulated gases via the attached suction and discharge piping. Continuous venting of the suction piping to the Volume Control tank (VCT) and manual venting of the discharge piping high points satisfies the pump casing venting requirements for the CCPs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. The following ECCS pumps are required to develop the indicated differential pressure on recirculation flow:

1)	Centrifugal charging pump	$\geq$ 2370 psid,
2)	Safety injection pump	$\geq$ 1440 psid, and
3)	RHR pump	> 170 psid.

This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code and the Technical Requirements Manual provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances 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. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.7

The correct alignment of throttle valves in the ECCS flow path on an SI signal is necessary for proper ECCS performance. Valves 8810A, B, C, D

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.7 (continued)

are provided in the charging pump to cold leg injection lines. Valves 8822A, B, C, D are provided in the SI pump to cold leg injection lines. These manual throttle valves are positioned following flow balancing and have mechanical locks to ensure that the proper positioning for restricted flow to a ruptured cold leg is maintained and that the other cold legs receive at least the required minimum flow. Valves 8816A, B, C, D are provided in the SI pump to hot leg recirculation lines. These manual throttle valves are positioned following flow balancing and have mechanical locks to ensure flow balancing and to limit SI pump runout. The 18 month Frequency is based on the same reasons as those stated in SR 3.5.2.5 and SR 3.5.2.6.

SR 3.5.2.8

Periodic inspections of the containment 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 under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. FSAR, Sections 6.3 and 7.6.
4. FSAR, Chapter 15, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.
7. BTP EICSB-18, Application of the Single Failure Criteria to Manually-Controlled Electrically-Operated Valves.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS - Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: centrifugal charging (high head) and residual heat removal (RHR) (low head).

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

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

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

In MODE 4, an ECCS train consists of a centrifugal charging subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg

(continued)

BASES

LCO (continued)

injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS hot and cold legs.

This LCO is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4.

APPLICABILITY

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

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

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

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS centrifugal charging pump subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS centrifugal charging pump subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the

(continued)

BASES

ACTIONS

A.1 (continued)

required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop.

If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

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

B.1

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

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling pool during refueling, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies both trains of the ECCS and the Containment Spray System through a common suction line to each system's supply header during the injection phase of a loss of coolant accident (LOCA) recovery. A motor operated isolation valve is provided in each header to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump following receipt of the RWST - Low Low signal. Use of a single RWST to supply both trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

The switchover from normal operation to the injection phase of ECCS operation requires changing centrifugal charging pump suction from the CVCS volume control tank (VCT) to the RWST through the use of isolation valves. Each set of isolation valves is interlocked so that the VCT isolation valves will not begin to close until the RWST isolation valves are fully open. Since the VCT is under pressure, the preferred pump suction will be from the VCT until the tank is isolated. This will result in a delay in obtaining the RWST borated water. The effects of this delay are discussed in the Applicable Safety Analyses section of these Bases.

During normal operation in MODES 1, 2, and 3, the safety injection (SI) and residual heat removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

When the suction for the ECCS and Containment Spray System pumps is transferred to the containment sump, the RWST flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ECCS pumps.

(continued)

BASES

BACKGROUND (continued)

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating"; B 3.5.3, "ECCS - Shutdown"; and B 3.6.6, "Containment Spray Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The minimum boron concentration limit is an important assumption in ensuring the required shutdown capability. The maximum boron concentration is an explicit assumption in the inadvertent ECCS actuation analysis, although it is typically a non-limiting event and the results are very insensitive to boron

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

concentrations. Although it only has a minor effect, the maximum temperature is used in the feedline break and small break LOCA analyses; the minimum temperature is an assumption in both the MSLB and inadvertent ECCS actuation analyses, although the inadvertent ECCS actuation event is typically non-limiting.

The MSLB analysis has considered a delay associated with the interlock between the VCT and RWST isolation valves, and the results show that the departure from nucleate boiling design basis is met. The delay has been established as 27 seconds, with offsite power available, or 37 seconds without offsite power. This response time includes 2 seconds for electronics delay, a 15 second stroke time for the RWST valves, and a 10 second stroke time for the VCT valves.

For a large break LOCA analysis, the minimum contained water volume limit of 483,731 gallons and the lower boron concentration limit of 2400 ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core. The limits on minimum contained water volume and maximum boron concentration of the RWST also ensure a maximum equilibrium sump pH for the solution recirculated within containment after a LOCA which limits corrosion and hydrogen production. The limit on maximum boron concentration is also used to determine a minimum equilibrium sump pH. This minimum pH level minimizes the evolution of iodine and minimizes the effect of chloride stress corrosion on mechanical systems and components.

The upper limit on boron concentration of 2600 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 40°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The upper temperature limit of 120°F is used in the small break LOCA analysis and containment analysis.

Exceeding this temperature will result in a higher peak clad temperature, because there is less heat transfer from the core to the injected water for the small break LOCA and higher containment pressures due to reduced

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

The RWST satisfies Criteria 2 and 3 of 10CFR50.36(c)(2)(ii).

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and Containment Spray System pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also 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." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

(continued)

BASES

ACTIONS (continued)

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. Since the RWST volume is normally stable and the contained volume required is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.2 (continued)

Control Board indication may be used in the surveillances of the required indicated RWST water volume. The indicated level of 95%, which includes 5% measurement uncertainty, is a conservative verification of contained volume. Other means of surveillance which consider measurement uncertainty may also be used.

SR 3.5.4.3

The boron concentration of the RWST should be verified every 7 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the centrifugal charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI.

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

The ECCS flow balance assumes RCP seal injection is limited to 40 gpm with FCV-121 full open and centrifugal charging pump header at 130 psig or greater than the Reactor Coolant System pressure (i.e., the pressurizer).

This LCO ensures that seal injection flow of ≤ 40 gpm, with RCS pressure ≥ 2215 psig and ≤ 2255 psig and charging flow control valve full open, will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory.

Seal injection flow satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 1).

(continued)

BASES

LCO (continued

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a differential pressure and flow must be known. The flow line resistance is determined by assuming that the differential pressure between the RCS pressure and the centrifugal charging pump discharge pressure is greater than or equal to 145 psid above the RCS pressure. The valve settings established at the prescribed differential pressure result in a conservative valve position. The additional modifier of this LCO, the charging flow control valve being full open, is required since the valve is designed to fail open for the accident condition. With the differential pressure greater than or equal to 145 psid above the RCS pressure and control valve position as specified by the LCO, a flow restriction is established. It is this flow restriction that is used in the accident analyses.

The limit on seal injection flow, combined with the differential pressure limit and an open wide condition of the charging flow control valve, must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the plant shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4, where this LCO is no longer applicable.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

The surveillance ensures the seal injection flow is less than 40 gpm with charging header pressure greater than or equal to 145 psig (130 psig + 15 psig for instrument uncertainty) above RCS pressure.

Verification every 31 days that the manual seal injection throttle valves are adjusted to give a flow within the limit ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. The Frequency of 31 days is based on engineering judgment and is consistent with other ECCS valve Surveillance Frequencies. The Frequency has proven to be acceptable through operating experience.

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.

2. 10 CFR 50.46.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis Loss of Coolant Accident. Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat with a reactor cavity pit projection, and a hemispherical dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete reactor building is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

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

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

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed and sealed; and

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break and a rod ejection accident (REA) (Ref. 2 and 3). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for these DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 2 and 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.1% of containment air weight per day in the safety analysis at P_a = 48.3 psig. The calculated peak pressure for LOCAs is less than 48.3 psig (Ref. 3).

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

The containment satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and containment purge, hydrogen purge, and containment pressure relief valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

(continued)

BASES (continued)

APPLICABILITY

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

ACTIONS

A.1

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

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. The containment concrete visual examinations may be performed during either power operation, e.g., performed concurrently with other containment inspection-related activities, or during a maintenance or refueling outage. The visual examinations of the steel liner plate inside containment are performed during maintenance or refueling outages since this is the only time the liner plate is fully accessible. Failure to meet air lock and purge valve with resilient seal leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and < 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Chapter 15.
3. FSAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

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

The personnel air lock is nominally a right circular cylinder, approximately 9 ft in diameter, with a door at each end. The emergency air lock is approximately 5 ft 9 in inside diameter with a 2 ft 6 in door at each end (Ref. 4). On both air locks, doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, each airlock door is designed so that, with the other door open, it will withstand and seal against the containment internal design pressure. The personnel air lock has two spherical doors. The interior door has its convex side towards the inside of the containment. The exterior door has its concave side towards the inside of the containment. Each personnel air lock door is sealed by a hydraulically driven locking ring. The emergency air lock has flat circular doors. Each emergency air lock door is sealed by a manual mechanical door latch (Ref. 2). Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analyses.

APPLICABLE SAFETY ANALYSES

The DBAs that results in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 3). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 3). This leakage rate is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a = 0.1% of containment air weight per day, the maximum allowable

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment leakage rate at the calculated peak containment internal pressure P_a = 48.3 psig, following a DBA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

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

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment 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, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact

(continued)

BASES

ACTIONS (continued)

(during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

<u>A.1, A.2, and A.3</u>

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

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

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

(continued)

BASES

ACTIONS

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

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 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is 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 ensures 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 containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

(continued)

BASES

ACTIONS

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

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 initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

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

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the reliable nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months.

The 24 month Frequency is based on the need to perform this surveillance under the conditions that apply during a plant outage and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgement and is considered adequate given that the interlock is not challenged during use of the airlock.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Section 6.2
3. FSAR, Section 15
4. FSAR, Section 3.8

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetration flow paths not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close with or without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration flow path 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 (Containment isolation valves include process isolation valves and associated locked closed vent, drain and test connections. A listing of containment process isolation valves is provided in Technical Requirements Manual.) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-3 signal and isolates the remaining process lines, except systems required for accident mitigation. Instead of the Phase “A” isolation signal listed above, the Containment Purge, Hydrogen Purge and Containment Pressure Relief isolation valves receive a Containment Ventilation Isolation signal on receipt of a safety injection signal and on receipt of a containment high radiation condition. This radiation signal is not credited in the accident analysis and is not fully safety grade. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

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BASES

BACKGROUND (continued)

Containment Purge System (48 inch purge valves)

The Containment Purge System operates to supply outside air into the containment for ventilation and cooling or heating needed for prolonged containment access following a shutdown and during refueling. The system may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 48 inch Containment Purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 48 inch Containment Purge supply and exhaust isolation valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Hydrogen Purge System (12 inch purge valves)

The Hydrogen Purge System may only be used with the reactor shutdown and containment pressure less than 5 psig. Because the 12 inch Containment Hydrogen Purge supply and exhaust valves are not qualified for automatic closure from their open position under initial DBA conditions, they are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Containment Pressure Relief (18 inch discharge isolation valves)

The Containment Pressure Relief valves are operated to equalize containment internal and external pressures. The penetration has a effective diameter of three inches provided by the installation of a debris screen cover inside containment.

Since the 18 inch Containment Pressure Relief valves are designed to meet the requirements for automatic containment purge isolation valves [Ref. 3, 7 and 8] and have an effective opening of only 3 inches, these valves may be opened as needed in MODES 1, 2, 3, and 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including the Containment Purge, Hydrogen Purge, and Containment Pressure Relief valves) are minimized. The safety analyses assume that the 48 inch Containment Purge and 12 inch Hydrogen Purge valves are closed at event initiation.

For valves that do not normally provide a direct activity release path from containment, the DBA analysis assumes that, at the time of the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment pressure relief isolation total response time of 5 seconds includes signal delay and containment isolation valve stroke times.

The LOCA and REA offsite dose analysis assumes leakage from the containment at a maximum leak rate of 0.10 percent of the containment volume per day for the first 24 hours, and, for LOCA, at 0.05 percent of the containment volume per day for the duration of the accident. The Containment Pressure Relief penetration is the only flowpath explicitly addressed in the dose analysis, since it provides a direct activity release path from the containment to the environment. It is assumed to isolate within 5 seconds from when the monitored parameter (Pressurizer Pressure) exceeds its setpoint.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the 18 inch Containment Pressure Relief valves. Two valves in series provide assurance that the exhaust line can be isolated even if a single failure occurred. The inboard and outboard isolation valves are provided with independent power sources and fail closed on the loss of power or air. A debris screen is provided inside containment on the inlet. This arrangement was designed to preclude common mode failures from disabling both valves on a purge line.

The 48 inch Containment Purge and 12 inch Hydrogen Purge valves may be unable to close in the environment following a LOCA. Therefore, each of the Containment Purge and Hydrogen Purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. In this case, the single passive failure

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

criterion remains applicable to the containment purge valves. The Containment Purge and Hydrogen Purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

The containment isolation valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 48 inch Containment Purge and 12 inch Hydrogen Purge valves must be maintained sealed closed. The process isolation valves covered by this LCO are listed along with their associated stroke times in the Technical Requirements Manual (Ref. 6).

The normally closed containment isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact except as provided in Table 13.6.3-1 of the Technical Requirements Manual for valves that may be opened for operational consideration on an intermittent basis under administrative controls. These passive isolation valves/devices are those listed in Reference 9.

Containment Purge, Hydrogen Purge, and Containment Pressure Relief valves with resilient seals must meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

This LCO provides assurance that the containment isolation valves, and the Containment Purge, Hydrogen Purge, and Containment Pressure Relief valves, will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

LCO 3.6.3 is modified by a Note stating that the Main Steam Safety valves, Main Steam Isolation Valves, Feedwater Isolation Valves and Associated Bypass Valves, and Steam Generator Atmospheric Relief Valves are not

(continued)

BASES

LCO (continued)

addressed in this LCO. These containment penetration flow paths credit the steam generators and piping inside containment as a passive containment isolation barrier (i.e., closed system). These containment isolation valves are addressed by LCO 3.7.1 “Main Steam Safety Valves (MSSVs)”, LCO 3.7.2 “Main Steam Isolation Valves (MSIVs)”, LCO 3.7.3 “Feedwater Isolation Valves (FIVs) and Associated Bypass Valves”, and LCO 3.7.4 “Steam Generator Atmospheric Relief Valves (ARVs)” which provide the appropriate Required Actions in the event these valves are inoperable.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 48 inch Containment Purge and 12 inch Hydrogen Purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls. A single valve in purge penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.3.1.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

(continued)

BASES

ACTIONS (continued)

In the event the containment isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable except for Containment Purge, Hydrogen Purge and Containment Pressure Relief isolation valve leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification through a system walkdown (which may include the use of local or remote indicators), that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. 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 containment 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 (this includes power operated valves with power removed), 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 containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control 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 containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path 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 (this includes power operated valves with power removed), and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because 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 containment isolation valve and a closed system. The closed system inside containment for GDC-57 penetrations meet the requirements of Reference 3. The closed systems outside containment for GDC-55 and GDC-56 penetrations are in accordance with Reference 2. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

There are three types of penetrations to which Condition C applies:

1. All GDC-57 penetrations Main Steam (e.g., MSIVs, MSIV bypasses, SG Blowdowns, N2 supplies, MS Drains, SG Sample Lines) Feedwater (e.g., Feedwater supplies to SGs, AFW supplies to SGs, N2 supplies, Feedwater Bypass Lines, Unit 2 Feedwater Preheater Bypass Lines), CCW Supply and Return From Excess Letdown & R.C. Drain Tank Heat Exchanger, Unit 1 PAL, Airlock Hydraulic System). DBD-ME-013 Attachment 1 lists each such valve with the GDC-57 criterion and gives the valve arrangement sketch and the Flow Diagram reference (e.g., MS and FW items 1 thru 30, 73, 76, 79 and 82; CCW items 111 and 112).

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

2. Special case GDC-56 for the emergency sump isolation (DBD-ME-013 Attachment 1 RHR and CT items 125, 126, 127, and 128) which have a single containment isolation valve outside containment and a closed system outside containment.

3. Special case GDC-55 RHR suction line (DBD-ME-013 Attachment 1 RHR items 33 and 34) which have a single containment isolation valve inside containment and a closed system outside containment.

All other penetrations (GDC-55 and 56) have double isolation valves.

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 closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1, D.2 and D.3

In the event one or more Containment Purge, Hydrogen Purge, or Containment Pressure Relief isolation valves in one or more penetration flow paths are not within leakage limits, leakage must be reduced to within limits, or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve (this includes power operated valves with power removed), or blind flange. A Containment Purge, Hydrogen Purge, or Containment Pressure Relief isolation valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.7. The specified Completion Time is reasonable, considering that one valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated

(continued)

BASES

ACTIONS

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

following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification through a system walkdown (which may include the use of local or remote indicators), that those isolation devices outside containment capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the Containment Purge, Hydrogen Purge, or Containment Pressure Relief isolation valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.7 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.7 is 18 months per the Containment Leakage Rate Testing Program. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown to be acceptable based on operating experience. Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

E.1 and E.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 48 inch Containment Purge and 12 inch Hydrogen Purge valve is required to be verified sealed closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a Containment Purge or Hydrogen Purge valve. These valves are not designed to be opened in MODES 1 to 4. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A Containment Purge or Hydrogen Purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The Frequency is a result of an NRC initiative, Multi-Plant Action No. B-24 (Ref. 5), related to containment purge valve use during plant operations. In the event Containment Purge or Hydrogen Purge valve leakage requires entry into Condition D, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs.

SR 3.6.3.2

Not Used

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification through a system walkdown (which may include the use of local or remote indicators), that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are 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 positions, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are 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 positions, since these were verified to be in the correct position upon locking, sealing, or securing.

The first 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 access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

A second Note modifies the requirement to verify the blind flange on the fuel transfer canal. The refueling cavity area in containment is flooded only during plant shutdown for refueling. The flange is only removed to support refueling operations and replaced after drainage of the canal when no more fuel transfers between the fuel handling building and the containment will occur. Once replaced, the flange is not removed again until the next refueling. Since the removal of this flange is limited to refueling operations, and access to it is restricted during MODES 1, 2, 3, and 4, the probability of it being mispositioned between refuelings is small. Therefore, it is reasonable that it is only required to be verified closed after each drainage of the canal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. An automatic power operated containment isolation valve is a containment isolation valve which is required to be closed by an automatic (i.e., other than operator manual) actuation signal and is powered by other than manual actuation (e.g., by an air or motor operator). The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the FSAR [Ref. 2]. The isolation time and Frequency of this SR are in accordance with the Technical Requirements Manual and the Inservice Testing Program.

SR 3.6.3.6

Not used.

SR 3.6.3.7

The Containment Purge, Hydrogen Purge, and Containment Pressure Relief valves with resilient seals, are leakage rate tested per the requirements of 10 CFR 50, Apppendix J, Option B to ensure OPERABILITY.

The containment purge, hydrogen purge, and containment pressure relief valves are tested in accordance with the Containment Leakage Rate Testing Program. Leakage rate acceptance criteria applies as follows:

a. The inboard and outboard isolation valves with resilient material seals in each locked closed 48 inch containment purge and 12 inch hydrogen purge supply and exhaust penetration measured leakage rate is < 0.05 L_a when pressurized to P_a.

b. Each 18 inch containment pressure relief discharge isolation valve with resilient material seals measured leakage rate is < 0.06 L_a when pressurized to P_a.

The Note is a clarification that leakage rate testing is not required for containment purge valves with resilient seals when their penetration flow path is isolated by a leak tested blank flange.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.8

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each Phase “A” automatic containment isolation valve will actuate to its isolation position on a Phase “A” Isolation signal, each Phase “B” automatic containment isolation valve will actuate to its isolation position on a containment Phase “B” Isolation signal, and each pressure relief discharge valve actuates to its isolation position on a Containment Ventilation Isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.9

Not used

SR 3.6.3.10

Not used.

SR 3.6.3.11

Not used.

SR 3.6.3.12

Not used.

SR 3.6.3.13

Not used.

REFERENCES

1. FSAR, Section 15.
2. FSAR, Section 6.2.
3. Standard Review Plan 6.2.4.

(continued)

BASES

REFERENCES (continued)

4. Not used

5. Multi-Plant Action MPA-B024, “Venting and Purging Containments While at Full Power and Effect of LOCA.”

6. Technical Requirements Manual.

7. NUREG-0737, II.E.4.

8. BTP CSB 6-4.

9. DBD-ME-013.

10. 10 CFR 50, Appendix J, Option B.

11. Regulatory Guide 1.163 (September 1995).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients.

The containment was designed for an internal pressure load equivalent to 50 psig. The LOCA and SLB are examined under a variety of initial conditions to ensure that the containment design limit is not exceeded. Although only two cases can yield pressure and temperature peaks, there are several cases that are near these peaks; furthermore, the time to the maximum temperature or pressure also varies with the assumed initial conditions. The full spectrum of cases for both LOCA and SLB transients determines the envelopes for which plant equipment is qualified. The containment was also designed for an internal pressure load equivalent to -5 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure. The initial pressure condition used in this analysis was -0.5 psig. This resulted in a minimum pressure greater than the design load.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment

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BASES

APPLICABLE SAFETY ANALYSES (continued)

backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System. An instrument uncertainty of ± 0.2 psi is conservatively included in the pressure limits (-0.3 to +1.3 psig) to allow the use of installed instrumentation for pressure measurements.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

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

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 8 hours. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is reasonable to return pressure to normal.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

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

REFERENCES

1. FSAR, Section 6.2.

2. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

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

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No two DBAs are assumed to occur simultaneously or consecutively.

A spectrum of DBAs were analyzed assuming the worst single active failure.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F. The containment design temperature is 280°F.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The spectrum of DBA cases are used to establish the environmental qualification operating envelope for containment. The performance of required safety-related equipment, including the containment structure itself, is evaluated against this operating envelope to ensure the equipment can perform its safety function (Ref. 2). The temperature limit is also used in the Containment external pressure analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System (Ref. 1).

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a LOCA. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

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

APPLICABILITY

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

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an adjusted average is calculated using two temperature measurements, on fixed or portable instruments. The temperature measurements are taken at the following locations: a) the containment dome, at or above Elevation 1000'-6"; b) the containment floor, at or above Elevation 860'-0". At least one of the temperatures must be taken at or above Elevation 1000'-6". The locations within the containment were selected to provide a representative sample of the overall containment atmosphere. The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment temperature condition.

REFERENCES

1. FSAR, Section 6.2.

2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray System

BASES

BACKGROUND

The Containment Spray system provides containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray system is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," GDC 40, "Testing of Containment Heat Removal Systems," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup Systems," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems" (Ref. 1).

The Containment Spray System is an Engineered Safety Feature (ESF) system. It is designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System provides a method to limit and maintain post accident conditions to less than the containment design values.

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes two containment spray pumps, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred manually from the RWST to the containment sumps. The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA.

The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the residual heat removal and containment spray heat exchangers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

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BASES

BACKGROUND (continued)

The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-3 pressure signal or manually. An “S” signal automatically starts the four containment spray pumps. If containment pressure continues to increase, a “P” signal (Containment Pressure Hi-3) opens the containment spray pump discharge valves and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. The injection phase continues until ECCS transfer is complete (Ref. 7) and RWST level indicators ensure sufficient volume of water has been injected for switchover of containment spray to the sumps (Ref. 4). The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

APPLICABLE SAFETY ANALYSES

The Containment Spray System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the worst case single active failures for the respective DBAs (Ref. 3).

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is ≤ 48.3 psig (experienced during a LOCA). The analysis shows that the peak containment temperature is ≤ 345°F (experienced during an SLB). Both results meet the intent of the design basis.

(See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The bounding analyses and evaluations assume a unit

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

specific power level of 100% for the LOCA and 70% for the SLB, one containment spray train actuates, and initial (pre-accident) containment conditions of 120°F and 1.5 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a -3.79 psig containment pressure and is associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4.

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment “P” signal (High-3) pressure setpoint to achieving full flow through the containment spray nozzles. The Containment Spray System total response time includes diesel generator (DG) startup (for loss of offsite power), sequenced loading of equipment, containment spray pump startup, and spray line filling (Ref. 4).

The Containment Spray System satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one containment spray train is required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). The containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains must be OPERABLE. Therefore, in the event of an accident, at least one train operates, assuming the worst case single active failure occurs.

Each Containment Spray System train includes two spray pumps, spray headers, nozzles, valves, piping, instruments, and controls to ensure an

(continued)

BASES

LCO (continued)

OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal. Upon indication of the RWST level required for switchover, the suction flowpath must be capable of being manually transferred to the containment sump.

APPLICABILITY

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

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray train is adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With two containment spray trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification through a system walkdown (which may include the use of local or remote indicators), that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

Not Used

SR 3.6.6.3

Not Used

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head (specified in the Technical Requirements Manual) ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow via a test header. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray valve actuates to its correct position on an actual or simulated actuation of a containment “P” (High-3) signal and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment “S” (High-1) and “P” (High-3) pressure signals. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.5 and SR 3.6.6.6 (continued)

position under administrative controls. 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 3.6.6.7

Not Used

SR 3.6.6.8

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, confirmation of operability following maintenance activities that can result in obstruction of spray nozzle flow is considered adequate to detect obstruction of the nozzles. Confirmation that the spray nozzles are unobstructed may be obtained by utilizing foreign materials exclusion (FME) controls during maintenance, a visual inspection of the affected portions of the system, or by an air or smoke flow test following maintenance involving opening portions of the system downstream of the containment isolation valves or draining of the filled portions of the system inside containment. Maintenance that could result in nozzle blockage is generally a result of a loss of foreign material control or a flow of borated water through a nozzle. Should either of these events occur, a supervisory evaluation will be required to determine whether nozzle blockage is a possible result of the event. For the loss of FME event, an inspection or flush of the affected portions of the system should be adequate to confirm that the spray nozzles are unobstructed since water flow would be required to transport any debris to the spray nozzles. An air flow or smoke test may not be appropriate for a loss of FME event but may be appropriate for the case where borated water inadvertently flows through the nozzles.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.

2. 10 CFR 50, Appendix K.

3. FSAR, Section 6.2.1.

(continued)

BASES

REFERENCES (continued)

4. FSAR, Section 6.2.2.

5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

6. Technical Requirements Manual.

7. FSAR, Section 6.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the preferred spray additive. The NaOH added to the spray also ensures a pH value of between 8.25 and 10.5 of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The Spray Additive System consists of one spray additive tank that is shared by the two trains of spray additive equipment. Each train of equipment provides a flow path from the spray additive tank to two containment spray pumps and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line. The spray additive system, including the eductors, is designed to ensure the contents of the Chemical Additive Tank is injected into containment given any single active failure. Consequently, in the short term, the pH of a train of spray can vary from acidic (pH of approximately 4.5) to strong basic (pH of approximately 12.5). The low spray pH can only occur during injection prior to switchover to recirculation. The equilibrium sump solution pH, after mixing and dilution with the primary coolant and ECCS injection, is above 7 and adequate spray pH for long term iodine retention is achieved with the onset of the spray recirculation mode. The high spray pH can only occur after switchover to recirculation from the sump when spray additive is added to recirculated sump water. The high pH condition transient is bounded by the hydrogen generation analysis.

The Containment Spray System actuation signal opens the valves from the spray additive tank to the spray pump suctions. The 28% to 30% NaOH solution is drawn into the spray pump suctions. The spray additive tank

(continued)

BASES

BACKGROUND (continued)

capacity provides for the addition of NaOH solution to the water sprayed from the RWST into containment. The percent solution and volume of solution sprayed into containment ensures the appropriate long term containment sump pH. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of spray operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

APPLICABLE SAFETY ANALYSES

The Spray Additive System is essential to the removal of airborne iodine within containment following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that 56.3% of the containment free volume is covered by the spray (Ref. 1).

The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System and is discussed in the Bases for LCO 3.6.6, "Containment Spray System." The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the entire spray additive tank volume is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow to raise the average long term containment sump solution pH to a level conducive to iodine removal, namely, to between 8.25 and 10.5. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned, that automatic valves are capable of activating to their correct positions, and that the eductors are capable of adding the NaOH solution to the CSS flow.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory thus reducing potential releases to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the Spray Additive System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 72 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1 (continued)

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 through a system walkdown (which may include the use of local or remote indicators), that those valves outside containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The required volume may be surveilled using an indicated level band of 91% to 94% for the Spray Additive Tank which corresponds to an analytical limit band of 4900 gallons to 5314 gallons, respectively, and includes a 3.36% measurement uncertainty. The 184 day Frequency was developed 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, so that there is high confidence that a substantial change in level would be detected.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The 184 day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position on a Containment Spray Actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.5

To ensure correct operation of the Spray Additive System, flow through the Spray Additive System eductors is verified once every 5 years. Flow of between 50 and 100 gpm through the eductor test loops (supplied from the RWST) simulates flow from the Chemical Additive Tank. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow.

REFERENCES

1. FSAR, Chapter 6.5.

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 the 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.

Five MSSVs are located on each main steamline, outside containment, upstream of the main steam isolation valves, as described in the FSAR (Ref. 1). The MSSVs must have sufficient capacity to limit secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine reactor trip.

Operation with one or more inoperable MSSVs is allowable if the reactor power is appropriately reduced. This action ensures that if an event were to occur, the operable MSSVs would continue to provide adequate overpressure protection.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that most significantly challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in the FSAR, Section 15.2 (Ref. 3). Of these, the full power turbine trip without steam dump is typically the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

The safety analysis demonstrates that the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. One turbine trip analysis is performed assuming primary system pressure control via operation of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressurizer relief valves and spray. This analysis demonstrates that the DNB design basis is met. Another analysis is performed assuming no primary system pressure control, but crediting reactor trip on high pressurizer pressure and operation of the pressurizer safety valves.

This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure. All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature N-16 or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the atmospheric or condenser steam dump valves. The FSAR safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The FSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization may be determined by system transient analysis or conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

lowering the Power Range Neutron Flux-High setpoint to an appropriate value. When the Moderator Temperature Coefficient (MTC) is positive, the reactor power may increase above the initial value during an RCS heatup event (e.g., turbine trip). Thus, for any number of inoperable MSSVs it is necessary to reduce the trip setpoint if a positive MTC may exist at partial power conditions, unless it is demonstrated by analysis that a specified reactor power reduction alone is sufficient to prevent overpressurization of the steam system. The MSSVs are assumed to have one active failure mode. The active failure mode is an inadvertent opening and failure to reclose once opened. The passive failure mode which is the failure to open upon demand is not assumed (Ref. 3).

The MSSVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The accident analysis requires that five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 102% RTP. The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2, and the DBA analysis.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, to relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB or Main Steam System integrity.

APPLICABILITY

In MODES 1, 2, and 3, five MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization.

In MODES 4 and 5, there are no credible transients 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.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets the overpressure protection requirements.

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

A.1

In the case of only a single inoperable MSSV on one or more steam generators when the Moderator Temperature Coefficient is not positive a reactor power reduction alone is sufficient to limit primary side heat generation such that overpressurization of the secondary side is precluded for any RCS heatup event. Furthermore, for this case there is sufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Therefore, Required Action A.1 requires an appropriate reduction in reactor power within 4 hours.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as discussed below, with an appropriate allowance for calorimetric power uncertainty.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined by the governing heat transfer relationship from the equation $q = \dot{m}\ \Delta h$, where q is the heat input from the primary side, $\dot{m}$ is the steam flow rate and Δh is the heat of vaporization at the steam relief pressure (assuming no subcooled feedwater). For each steam generator,at a specified pressure, the maximum allowable power level is determined as follows:

$$\text{Maximum Allowable Power Level} \leq 100/Q\ (W_s\ h_{fg}\ N)/K$$

(continued)

BASES

ACTIONS (continued)

where:

Q	=	Nominal NSSS power rating of the plant (including reactor coolant pump heat), Mwt.
K	=	Conversion factor, 947.82 (Btu/sec)/Mwt
W_s	=	Minimum total steam flow rate capability of the OPERABLE MSSVs on any one steam generator at the highest OPERABLE MSSV opening pressure including tolerance and accumulation, as appropriate, in lb/sec.
h_{fg}	=	Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm.
N	=	Number of loops in plant.

For use in deterimining the % RTP in Action A, the Maximum NSSS Power calculated above is reduced by 2% RTP to conservatively account fo the calorimetric power uncertainty.

B.1 and B.2

In the case of multiple inoperable MSSVs on one or more steam generators, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Furthermore, for a single inoperable MSSV on one or more steam generators when the Moderator Temperature Coefficient is positive the reactor power may increase as a result of an RCS heatup event such that flow capacity of the remaining OPERABLE MSSVs is insufficient. The 4 hour Completion Time for Required Action B.1 is consistent with A.1. An additional 32 hours is allowed in Required Action B.2 to reduce the setpoints. The Completion Time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a system transient analysis with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

To determine the Table 3.7.1-1 Maximum Allowable Power for Action B (% RTP), the calculated Maximum NSSS Power is reduced by 9.0% to account for Nuclear Instrumentation System trip channel uncertainties.

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1, "Reactor Trip System Instrumentation," provide sufficient protection.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2 correspond to ambient conditions of the valve at nominal 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. 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. FSAR, Section 10.3.1 and 10.3.2.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.

3. FSAR, Chapter 15.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

5. 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 high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are located downstream from the main steam safety valves (MSSVs), the steam generator atmospheric relief valves (ARVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV, ARV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by either low steamline pressure, high containment pressure or high steam line pressure rate. Each MSIV has an electrical two train module to ensure that the valves can be closed even if one train fails. The valves also fail closed on loss of hydraulic fluid.

Each MSIV has an MSIV bypass valve which is locked closed during power operations. During startup, hot standby and hot shutdown, one MSIV bypass valve may be opened provided the other three bypass valves are locked closed and their associated MSIVs are closed. The MSIVs may be actuated manually as a group or individually if required.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The basis for the MSIV operability is derived from their assumed operation in the accident analyses of the breaks in the secondary system (principally steamline break). The design of the secondary system precludes the uncontrolled blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand). In addition, the MSIVs are credited in the analyses of the steam generator tube rupture accidents (Ref. 3).

In the safety analyses, several different SLB events are compared against different event acceptance limits. A double-ended guillotine SLB at hot zero power is the limiting case with respect to core response. The double-ended guillotine SLB outside containment is limiting for offsite dose consequences.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

A spectrum of non-mechanistic break upstream of the MSIVs in the steam tunnels from at power conditions are limiting with respect to environmental qualification in the steam tunnels, although a break in this short section of piping has a very low probability and is postulated for environmental qualification purposes only. A large SLB at higher power levels is limiting with respect to containment temperature used for equipment qualification. In the analysis of feedwater line break and steam generator tube rupture accidents, the MSIVs are credited for steam generator isolation. A significant failure conservatively considered for all cases is the failure of a MSIV to close.

The MSIVs remain open during power operation and their safety function is to close on demand. These valves are assumed to operate under the following situations:

a. An HELB (SLB or FLB) inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator fails to close. For this scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not postulated due to the break exclusion design of the piping. [NOTE: Although a break in this area is not assumed for accident analyses, a non-mechanistic pipe crack is postulated for equipment qualification.]

c. A break downstream of the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases. In addition to minimizing radiological releases, this enables the operator to maintain the pressure of the steam generator with the ruptured tube at the MSSV setpoints, a necessary step toward isolating the flow through the rupture.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. The MSIVs are also utilized during other events such as a feedwater line break and LOCA (for containment isolation). These events are less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits and the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3, except when closed and de-activated, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIVs are closed, however, because the steam generator energy is low, an inadvertent steam release in this plant condition does not require the MSIVs to be closed to ensure the effects are within the analyzed envelopes.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 8 hour Completion Time is greater than that normally allowed for

(continued)

BASES

ACTIONS

A.1 (continued)

GDC-55 and GDC-56 containment isolation valves because the MSIVs are GDC-57 valves that isolate a closed system penetrating containment. These valves differ from GDC-55 and GDC-56 containment isolation valves in that the closed system provides an additional means for containment isolation.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, 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 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV. Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed but not deactivated, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed 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 at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5 seconds. The hand switch may be used as the actuation signal to perform this surveillance. The MSIV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage.

The Frequency is in accordance with the Inservice Testing (IST) Program. This test is allowed to be 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 a delay of testing until MODE 3, 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 main steam line isolation 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 test is allowed to be 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 a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. FSAR, Section 10.3.
2. FSAR, Section 6.2.
3. FSAR, Chapter 15.
4. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.3 Feedwater Isolation Valves (FIVs) and Feedwater Control Valves (FCVs) and Associated Bypass Valves

BASES

BACKGROUND

The safety grade FIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). Each Unit 1 FIV has a FIV Bypass Valve (FIBV) which is its associated bypass valve. Each Unit 2 FIV has a FIV Bypass Valve (FIBV) and a Feedwater Preheater Bypass Valve (FPBV) which are its associated bypass valves. The associated function of the Feedwater Control valves (FCVs) and their associated bypass valves (FCBVs) is to provide backup isolation of MFW flow to the secondary side of the steam generators following an HELB. Because an earthquake is not assumed to occur coincident with a spontaneous break of safety related secondary piping, loss of the non-safety grade FCVs is not assumed [Ref. 3]. If the single active failure postulated for a secondary pipe break is the failure of a safety grade FIV to close, then credit is taken for closing the non-safety grade FCV or tripping the feedwater pump in that line.[Ref. 3] Closure of the FIVs and associated bypass valves or FCVs and associated bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FLBs) occurring upstream of the FIVs or FCVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the FIVs will be mitigated by their closure. Closure of the FIVs and associated bypass valves, or FCVs and associated bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FLBs inside containment, and reducing the cooldown effects for SLBs.

The FIVs and associated bypass valves, and the main feedwater check valves, isolate the nonsafety related portions from the safety related portions of the system. In the event of a feedwater pipe rupture in the nonsafety portion of the system, the check valves will close to terminate the loss of fluid from the secondary side. In the event of a secondary side pipe rupture inside containment, the FIVS and associated bypass valves limit the quantity of high energy fluid that enters containment through the break. The FIV check valves provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One FIV and an associated bypass valve (FIBV), and one FCV and its associated bypass valve, are located on each MFW line, outside but close to containment. The Unit 2 preheater bypass valve associated with the Unit 2 FIV is located in a branch (preheater bypass) line downstream of the FCV between the feedwater isolation check valve and FIV. On Unit 1, the AFW

(continued)

BASES

BACKGROUND (continued)

injection point is in FW piping not connected to the main feedwater line. On Unit 2, the AFW injection point is in the Unit 2 preheater bypass line outside but close to containment. The Unit 2 preheater bypass valves and FCVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following preheater bypass valve or FCV closure.

The FIVs are located in separate piping from the AFW so that AFW may be supplied to the steam generators following FIV closure. The piping volume from the FIV and associated bypass valves to the steam generators must be accounted for in calculating mass and energy releases, and purged prior to AFW reaching the steam generator following either an SLB or FWLB.

The FIVs and associated bypass valves, and FCVs and associated bypass valves, close on receipt of a safety injection signal, T_{avg} - Low coincident with reactor trip (P-4) or steam generator water level - high high signal. They may also be actuated manually as a group or individually. Each FIV and associated bypass valves and each FCV and associated bypass valve is a two train valve (i.e., both Train A and Train B controls are independently provided to perform the close function. Therefore, single active failure of the FIV and associated bypass valves is not assumed; however, the FCVs and associated bypass valves are provided as a backup in the unlikely event a mechanical failure prevented the primary isolation valves from fully closing.

A description of the FIVs and associated bypass valves and the FCVs and associated bypass valves is found in the FSAR, Chapters 6, 7, 10 and 15 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the FIVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FLB. Closure of the FIVs and associated bypass valves may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level - high high signal.

Failure of an FIV, or the associated bypass valves to close following an SLB or FLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FLB event.

The FIVs and associated bypass valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The associated function of the Feedwater Control valves (FCVs) and their associated bypass valves is to provide backup isolation of MFW flow to the secondary side of the steam generators following an HELB.

The FCVs and associated bypass valves satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

This LCO ensures that the FIVs, FCVs, and their associated bypass valves will isolate MFW flow to the steam generators, following an FLB or main steam line break. The associated bypass valves for each FIV are the feedwater isolation bypass valve and the associated feedwater preheater bypass valve.

This LCO requires that four FIVs and associated bypass valves and four FCVs and associated bypass valves be OPERABLE. The FIVs and FCVs and the associated bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FLB inside containment. Because a feedwater isolation signal on high steam generator level is relied on to terminate an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The FIVs and FCVs and the associated bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. The FIV and associated bypass valve operability ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. The FCV and associated bypass valve operability ensures that, in the event of a FIV or associated bypass valve inoperability, the safety function would still be maintained. In MODES 1, 2, and 3, the FIVs and FCVs and the associated bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the FIVs, FCVs, and the associated bypass valves are normally closed since MFW is not required.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate condition entry is allowed for each valve.

A.1 and A.2

With one FIV 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, based on operating experience.

Inoperable FIVs 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, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated. LCO 3.0.5 allows the FIVs to be opened as needed for post maintenance testing to demonstrate operability.

B.1 and B.2

With one FCV 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 backup safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable FCVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated. LCO 3.0.5 allows the FIVs to be opened as needed for post maintenance testing to demonstrate operability.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one associated bypass 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 valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable associated bypass 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, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated. LCO 3.0.5 allows the FIV bypass valves to be opened as needed for post maintenance testing to demonstrate operability.

D.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 of 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 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. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the FIV or FCV, or otherwise isolate the affected flow path.

E.1 and E.2

If the FIVs and FCVs and the associated bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated within the associated

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from 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 FIV, FCV, and associated bypass valves is ≤ 5 seconds. The FIV and FCV isolation times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. This is consistent with RG 1.22 (Ref. 4).

The Frequency for this SR is in accordance with the Inservice Testing Program. Per Ref. 5, if it is necessary to adjust stem packing to stop packing leakage and if a required stroke test is not practical in the current plant mode, it should be shown by analysis that the packing adjustment is within torque limits specified by the manufacturer for the existing configuration of packing, and that the performance parameters of the valve are not adversely affected. A confirmatory test must be performed at the first available opportunity when plant conditions allow testing. Packing adjustments beyond the manufacturer’s limits may not be performed without (1) an engineering analysis and (2) input from the manufacturer, unless tests can be performed after adjustments.

SR 3.7.3.2

This SR verifies that each FIV and associated bypass 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 of this surveillance 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.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Chapters 6, 7, 10 and 15.
2. Not used.
3. NUREG-0138, “Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1076 Memorandum from Director, NRR to NRR Staff,” November 1976.
4. RG 1.22, “Periodic Testing of Protection System Actuation Functions,” (2/17/72).
5. NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants.”

B 3.7 PLANT SYSTEMS

B 3.7.4 Steam Generator Atmospheric Relief Valves (ARVs)

BASES

BACKGROUND

The ARVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Dump System to the condenser not be available, as discussed in the FSAR, Section 10.3 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The ARVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Steam Dump System.

One ARV line for each of the four steam generators is provided. Each ARV line consists of one ARV, its associated remote manual controls and an associated block valve.

The ARVs are provided with upstream block valves to permit their being tested at power and to provide an alternate means of isolation. The ARVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ARVs are provided with pressurized air accumulators that, on a loss of pressure in the normal instrument air supply, automatically supply air to operate the ARVs. With 80 psig pressure, the air accumulators have sufficient capacity to operate the ARVs for the time required for Steam Generator Tube Rupture mitigation. In addition, handwheels are provided for local manual operation should the accumulator pressure fall to the point where it can no longer control the ARVs.

A description of the ARVs is found in Reference 1. The ARVs are OPERABLE with only a DC power source available, however, the automatic controls for the ARVs do not perform a safety function.

APPLICABLE SAFETY ANALYSES

The design basis of the ARVs for the minimum relief capacity is established by the capability to cool the unit to RHR entry conditions and the capability to mitigate a SGTR, The design basis for the maximum relief capacity is established by the 10CFR100 limits for SGTR and the capacity of the MSSVs assumed in the accident analyses. The design rate of 50ºF per hour is applicable for a natural circulation cooldown using two steam generators, each with one ARV. The unit can be cooled to RHR entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the safety analysis presented in References 1 and 2, the ARVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for events accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ARVs. Four ARVs are required to be OPERABLE to satisfy the SGTR accident analysis requirements based on consideration of single failure assumptions regarding the failure of one or two ARVs to open on demand.

The ARVs are equipped with block valves in the event an ARV fails to close during an STGR event.

The ARVs and block valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Four ARV lines are required to be OPERABLE. One ARV line is required from each of four steam generators to ensure that at least two ARV lines (Unit 1) or one ARV line (Unit 2) is available to conduct a timely unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a postulated single failure which renders unavailable one (Unit 1) or two (Unit 2) ARVs on unaffected steam generators. The block valves must be OPERABLE to isolate a failed open ARV line. A closed block valve renders its ARV line inoperable as it cannot be operated remotely from the control room.

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the Steam Dump System.

An ARV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand using associated remote manual control.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the ARVs are required to be OPERABLE.

In MODE 4, 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ARV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ARV lines, a nonsafety grade backup in the Steam Dump System, and MSSVs.

B.1

With two ARV lines inoperable, action must be taken to restore at least one ARV line to OPERABLE status. This will result in at least three OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 72 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

C.1

With three or more ARV lines inoperable, action must be taken to restore at least two ARV line to OPERABLE status. This will result in at least two OPERABLE ARVs. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

D.1 and D.2

If the ARV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ARVs must be able to be opened remotely and throttled through their full range. This SR ensures that the ARVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ARV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the Inservice Testing Program Frequency. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ARV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement at least once per fuel cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the Inservice Testing Program Frequency. The Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Sections 3.9B, 5A, 9.3 and 10.3.
2. FSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The motor-driven AFW pumps take suction through a common suction line and the turbine-driven pump takes suction through a separate and independent suction line from the condensate storage tank (CST) (LCO 3.7.6) and pump to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping outside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric relief valves (LCO 3.7.4). If the main condenser is available, steam may be released via the steam dump valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. Each motor driven pump provides 100% of AFW flow capacity, and the turbine driven pump provides 200% of the required capacity to the steam generators, as assumed in the accident analysis. The pumps are equipped with miniflow recirculation lines to prevent pump operation against a closed system. The miniflow line for the motor driven pump automatically isolate on a flow signal. The miniflow line for the turbine driven pump does not isolate and remains open during pump operation. Each motor driven AFW pump is powered from an independent Class 1E power supply and feeds two steam generators, although each pump has the capability to be locally realigned to feed other steam generators. The steam turbine driven AFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump. The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions. Each steam feed line is provided with a check valve that prevents loss of steam supply to the turbine driven pump should a piping failure affect the secondary side of the steam generator for that supply line.

The turbine driven AFW pump supplies a common header capable of feeding all steam generators with normally open, DC powered, air operated control valves. One pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

(continued)

BASES

BACKGROUND (continued)

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the lowest set pressure of the MSSVs plus accumulation. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ARVs.

The AFW System actuates automatically on steam generator water level - low-low by the ESFAS (LCO 3.3.2). The system also actuates on loss of offsite power and on an ATWS Mitigation System Actuation Circuitry (AMSAC) signal, however, AMSAC start of the AFW pumps is not required for AFW system operability. The motor driven pumps also start on safety injection and trip of all MFW pumps. During normal plant operations, the AFW system, under manual control, is used to maintain SG water level.

The AFW System is discussed in the FSAR (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3% accumulation.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and MFW line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FLB); and

b. Loss of MFW.

In addition, AFW flow is considered in the small break loss of coolant accident (SBLOCA), but does not have a significant effect on the transient characteristics.

The AFW System design is such that it can perform its function following a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

FLB, combined with a loss of offsite power following turbine trip, and a single active failure of one AFW pump. Flow to the faulted steam generator is restricted to limit the mass and energy release into containment. One motor driven AFW pump and the turbine-driven pump would deliver to the MFW header at the maximum flow of 1380 gpm, limited by flow restricters installed in the AFW lines, until the faulted loop was identified, and flow terminated by the operator using either the motor operated isolation valve or flow control valve in each supply line. Each flow control valve has an air accumulator with sufficient capacity to close the valve and maintain it closed for up to 30 minutes. Sufficient flow would be delivered to at least two intact steam generators by one of the redundant motor-driven pumps or by one of the motor-driven pumps and the turbine-driven AFW pump.

The ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC powered, air operated valves are provided for each AFW line to control the AFW flow to each steam generator. These valves fail open on loss of air; air accumulators are provided to close them if required. If instrument air is unavailable, the flow may be controlled by local manual operation of the flow control valves.

Both steam supply lines are required to be OPERABLE to mitigate secondary side pipe failures since one of the two might be lost due to the direct effects of the failure.

The AFW System satisfies the requirements of Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This

(continued)

BASES

LCO (continued)

requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to separate steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the FW is lost. In addition, the AFW 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 AFW System may be used for heat removal via the steam generators. See the BASES for 3.4.7.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

(continued)

BASES

ACTIONS (continued)

B.1

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 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.

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, “RCS Loops - MODE 4.” Although not required, the unit may continue to cool down and initiate RHR.

D.1

If all three AFW trains are 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 related 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 one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves 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 being mispositioned are in the correct position.

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

This SR is modified by a note stating that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator water level control, if it is capable of being manually realigned to the AFW mode of operation and provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable and applies only when the unit is below 10% RATED THERMAL POWER. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY is maintained. The ability to realign the affected AFW train(s) to a standby condition or to an in-service condition supplying feedwater to the steam generator(s) assures the intended safety function is available. Realignment of the AFW train(s)is normally performed from the Control Room. However, when explicitly allowed by Operations' procedure, this provision may also be applied to local manual operation of AFW valves.

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref. 2). The motor driven pumps should develop a differential pressure of $\geq$ 1380 psid at a flow of $\geq$ 430 gpm. The turbine driven pump should develop a differential pressure of $\geq$ 1438 psid at a flow of $\geq$ 860 gpm. Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow through a test line. This test confirms one point on the pump design curve

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.2 (continued)

and is indicative of overall performance. Instrument uncertainty is not included in the above flow and differential pressure values but is addressed in the surveillance testing procedure. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation generated by an auxiliary feedwater actuation signal. The Steam Generator Blowdown, Steam Generator Blowdown Sample, and Unit 2 Feedwater Split Flow Bypass valves close on an auxiliary feedwater actuation to ensure auxiliary feedwater is delivered to the steam generator upper nozzles and is retained in the steam generator for decay heat removal. The AFW flow control valves trip to auto (open) on an auxiliary feedwater actuation to ensure full flow is delivered to each steam generator flow path. The steam admission valves open to supply the turbine driven auxiliary feedwater pump. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required 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 the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

This SR is modified by a note stating that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator water level control, if it is capable of being manually realigned to the AFW mode of operation and provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable and applies only when the unit is below 10% RATED THERMAL POWER. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.3 (continued)

and these manual operations are an accepted function of the AFW system, OPERABILITY is maintained. The ability to realign the affected AFW train(s) to a standby condition or to an in-service condition supplying feedwater to the steam generator(s) assures the intended safety function is available. Realignment of the AFW train(s) is normally performed from the Control Room. However, when explicitly allowed by Operations' procedure, this provision may also be applied to local manual operation of AFW valves.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation generated by an auxiliary feedwater actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the autostart function is not required. 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 SR is modified by two notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator water level control, if it is capable of being manually realigned to the AFW mode of operation and provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable and applies only when the unit is below 10% RATED THERMAL POWER. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY is maintained. The ability to realign the affected AFW train(s) to a standby condition or to an in-service condition supplying feedwater to the steam generator(s) assures the intended safety function is available. Realignment of the AFW train(s) is normally performed from the Control Room. However, when explicitly allowed by Operations' procedure, this provision may also be applied to local manual operation of AFW valves.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Sections 7.3 and 10.4.9.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND	The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric relief valves. The AFW pumps operate with miniflow recirculation to the CST as required. When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam dump valves. The condensed steam is returned to the CST by the condensate transfer pump. This has the advantage of conserving condensate while minimizing releases to the environment. Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena. The CST is designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from alternate sources. The safety-related back-up supply is provided by manual switchover of AFW pump suctions to the Station Service Water System. A description of the CST is found in the FSAR (Refs. 1, 3 & 5).
APPLICABLE SAFETY ANALYSES	The CST provides cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the FSAR, Chapter 15 (Ref. 3). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the bounding analysis assumption is 4 hours at MODE 3, steaming through the MSSVs, followed by a cooldown to residual heat removal (RHR) entry conditions at the design cooldown rate of 50ºF/hour (Refs. 4 and 5). This assumption does not include reactor coolant pump heat. The CST satisfies Criteria 2 and 3 of 10CFR50.36(c)(2)(ii).
LCO	To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single active failure. In

(continued)

BASES

LCO (continued)

doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown.

The CST level of 53% is as indicated on the main control board and is based on a required volume of 241,000 gallons (includes allowances for un-usable volume and instrument uncertainties). This volume is sufficient to hold the unit in MODE 3 for 4 hours, followed by a cooldown to RHR entry conditions at 50ºF/hour for 5 hours. This basis is established in Reference 5 and exceeds the volume required by the accident analysis.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

APPLICABILITY

In MODES 1, 2, and 3, the CST is required to be OPERABLE.

In MODE 4, 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CST level is not within limits, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE, and that the SSWS is Operable. In addition, each motor operated valve between the SSWS and each Operable AFW pump must be OPERABLE. The CST must be restored to OPERABLE status within 7 days, because the backup supply is not condensate grade water. 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 CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. (The required CST volume surveillance of 53% level is based on the use of control board indications which include a 3.5% measurement uncertainty. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, 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 the CST level.

REFERENCES

1. FSAR, Sections 3.9B, 7.3, and 9.2.6.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. BTP RSB 5-1, Design Requirements of the Residual Heat Removal System.
5. FSAR Appendix 5A.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components, as well as the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System, and thus to the environment.

The CCW System is arranged as two independent, full capacity cooling loops (safeguards loops), and has isolatable nonsafety related components. A common non-safeguards loop is provided for non-essential cooling loads as well as spent fuel pool cooling. Each safeguards loop train includes a full capacity pump, heat exchanger, piping, valves, and instrumentation. Each safety related train is powered from a separate bus. An open surge tank in the system provides protective functions to ensure that sufficient net positive suction head is available. In the event an accident, various system valves are repositioned by an ESF actuation signal (i.e., a Safety Injection Actuation Signal and/or a Containment Spray Actuation Signal) as described in the FSAR (Ref. 1). The pump in each train is automatically started on receipt of a safety injection signal, and the non-safeguards loop is isolated on receipt of a Containment Spray Actuation Signal.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.2.2 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW train to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase, with a maximum CCW temperature of 135ºF (Ref. 2). The Emergency Core Cooling System (ECCS) LOCA and containment OPERABILITY LOCA each model the maximum and minimum performance of the CCW System, respectively. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System (RCS) by the ECCS pumps.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The normal temperature of the CCW is less than 108ºF, and, during unit cooldown to MODE 5 (T_{cold} < 200ºF), a maximum temperature of 122ºF is maintained.

The CCW System also functions to cool the unit from RHR entry conditions (T_{avg}< 350ºF), to MODE 5 (T_{avg} < 200ºF), during normal and post accident operations. The time required to cool from 350ºF to 200ºF is a function of the time after shutdown and the number of CCW and RHR trains operating. One CCW train is sufficient to remove decay heat during subsequent operations with T_{avg} < 200ºF. This assumes a maximum service water temperature of 102ºF occurring simultaneously with the maximum RHR heat loads on the system.

The CCW System satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCW train is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CCW must be OPERABLE.

At least one CCW train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CCW train is considered OPERABLE when:

a. The pump and associated portion of the surge tank are OPERABLE; and

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

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," be entered if an inoperable CCW train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1 (continued)

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 being mispositioned are in the correct position.

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

SR 3.7.7.2

This SR verifies proper automatic operation of each automatic CCW valve on its associated actual or simulated ESF actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required 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 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 verifies proper automatic operation of the CCW pumps on an actual or simulated Safety Injection actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Sections 3.9B, 7.3, and 9.2.2.
2. FSAR, Section 6.2.

B 3.7 PLANT SYSTEMS

B 3.7.8 Station Service Water System (SSWS)

BASES

BACKGROUND

The SSWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SSWS also provides this function for various safety related. The safety related functions are covered by this LCO.

The SSWS consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of one 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned to be operable in the unlikely event of a loss of coolant accident (LOCA). The pumps aligned to their respective loops are automatically started upon receipt of a safety injection signal. An automatic valve in the discharge of each pump is interlocked to open on a pump start. An automatic valve in the SSWS cooling water flow path for each emergency diesel generator automatically opens on a diesel generator start. All other valves are manual valves operated locally. The SSWS also is the backup water supply to the Auxiliary Feedwater System.

Cross-connections are provided between trains and between units such that any pump can supply any other pump's required flow.

Train isolation by two normally closed valves in series or one locked closed valve is provided to satisfy GDC-44. Unit isolation by one locked closed valve is provided to satisfy GDC-5 (Ref. 5).

In the event of a total Loss of Station Service Water (LOSSW) event in one unit at Comanche Peak, backup cooling capability is available via a cross-connect between the two units (References 1, 4 and 6). An OPERABLE pump is manually realigned and flow balanced to provide cooling to essential heat loads to one or both units as required. The OPERABILITY of the unit cross-connect along with a Station Service Water pump in the shutdown unit ensures the availability of sufficient redundant cooling capacity for the operating unit. The Limiting Condition of Operation will ensure a significant risk reduction as indicated by the analyses of a Loss of Station Service Water System event. The surveillance requirements ensure the short and long-term OPERABILITY of the Station Service Water System and cross-connect between the two units.

The Station Service Water System cross-connect between the two units consists of appropriate piping and cross-connect valves connecting the

(continued)

BASES

BACKGROUND (continued)

discharge of the Station Service Water pumps of the two units. By aligning the cross-connect flow paths, additional redundant cooling capacity from one unit is available to the Station Service Water System of the other unit.

Additional information about the design and operation of the SSWS, along with a list of the components served, is presented in the FSAR, Section 9.2.1 (Ref. 1). The principal safety related function of the SSWS is the removal of decay heat from the reactor via the CCW System.

APPLICABLE SAFETY ANALYSES

The design basis of the SSWS is for one SSWS train, in conjunction with the CCW System and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA as discussed in the FSAR, Section 6.2 (Ref. 2). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the ECCS pumps. The SSWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SSWS, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR), as discussed in the FSAR, Section 5.4.7 (Ref. 3) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the time after shutdown and number of CCW and RHR System trains that are operating. One SSWS train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum SSWS temperature of 102ºF occurring simultaneously with maximum heat loads on the system.

The SSWS satisfies Criterion 3 of 10CFR50.36(c)(2)(ii). The requirement for cross connections and opposite unit pumps satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

Two SSWS trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming that the worst case single active failure occurs coincident with the loss of offsite power.

An SSWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The pump is OPERABLE; and

(continued)

BASES

LCO (continued)

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

A SSW Pump on the opposite unit is OPERABLE as back-up in the event of a LOSSW if it is capable of providing required flow rates. An emergency diesel generator power source is not required because loss of offsite power is not assumed coincident with a LOSSW event.

A cross-connect valve is OPERABLE if it can be cycled or is locked open. A valve that cannot be demonstrated OPERABLE by cycling is considered inoperable until the valve is surveilled in the locked open position. However, at least one cross-connect valve between units is required to be maintained closed in accordance with GDC-5 unless required for flushing or due to total loss of Station Service Water pumps for either unit.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SSWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SSWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SSWS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If no SSW pump on the opposite unit or its associated cross-connects are operable, the overall reliability is degraded since a back-up in the event of a Loss of Station Service Water System (LOSSWS) event may not be capable of performing the function. The 7 day completion time is based on the low probability of a LOSSWS during this time period.

B.1

If one SSWS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SSWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SSWS train could result in loss of SSWS 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 SSWS train results in an inoperable emergency diesel

(continued)

BASES

ACTIONS

B.1 (continued)

generator. 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 SSWS train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

C.1 and C.2

If the SSWS train or an SSW Pump on the opposite unit and its associated cross-connects cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the SSWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SSWS.

Verifying the correct alignment for manual, power operated, and automatic valves in the SSWS flow path provides assurance that the proper flow paths exist for SSWS 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 being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

This SR verifies proper position or manual operation of the cross-connect valves between units. The 92 day frequency is based on the frequency in ASME XI (Ref. 7) for testing of Category A and B valves and is consistent with Generic Letter 91-13 (Ref. 4).

SR 3.7.8.3

This SR verifies proper automatic operation of the SSWS pumps on an actual or simulated Safety Injection actuation signal. The SSWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. 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 the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.2.1.
2. FSAR, Section 6.2.
3. FSAR, Section 5.4.7.
4. Generic Letter 91-13, "Request for Information related to the Resolution of Generic Issue 130, Essential Service Water System Failures at Multi-unit Sites, Pursuant to 10 CFR 50.54(f)."
5. General Design Criteria 5 and 44.
6. TXX-92410, "License Amendment Request 92-002, Combined Unit 1 and 2 Technical Specifications" dated August 31, 1992.
7. ASME XI.

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS for both CPSES units (1 & 2) is the Safe Shutdown Impoundment (SSI). The SSI is formed by a cove of Squaw Creek Reservoir (SCR) and is retained by a seismic Category I dam (SSI Dam). The normal SCR/SSI elevation is 770 feet mean sea level. An equalization channel between the SSI and SCR has an invert elevation of 769'-6" to ensure the required SSI volume is retained should the main SCR dam fail. The SSI provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Station Service Water System (SSWS) and the Component Cooling Water (CCW) System.

The SSI has been defined as that water source, including necessary retaining structures (e.g., a pond with its dam), and the intake channel entering, but not including, the service water system intake structure as discussed in the FSAR, Section 2.4 and 9.2.5 (Ref. 1). The two principal functions of the SSI are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The basic performance requirements are that a 30 day supply of water be available, and that the design basis temperatures of safety related equipment not be exceeded. The CPSES thermal-hydraulic analysis of the SSI assumed no make-up water was added for a period of 39 days. The analysis shows that the peak SSI temperature would occur approximately a week following a design basis event.

Additional information on the design and operation of the SSI can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The SSI is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. Its maximum post accident heat load occurs approximately 20 minutes after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and RHR are required to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

single failure (e.g., failure of the main cooling reservoir dam). The thermal-hydraulic analysis assumes an initial elevation of 770 feet mean sea level which drops to 769'-6" coincident with the Design Basis Event. The SSI is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the SSI.

The SSI satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The SSI is required to be OPERABLE and is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the SSWS to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SSWS. To meet this condition, the Station Service Water System intake temperature should not exceed 102ºF and the level should not fall below 770 ft mean sea level during normal unit operation.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SSI is required to support the OPERABILITY of the equipment serviced by the SSI and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the SSI are determined by the systems it supports.

ACTIONS

A.1

If the level drops below that required, action must be taken to restore the SSI to OPERABLE status within 7 days. The assumption of the loss of the main reservoir and the analysis for 39 days with no make-up are conservatisms in the evaluation of water volume that provide a design margin exceeding the margin of safety in RG 1.27. The SSI has sufficient volume below the required level to meet RG 1.27 requirements for 30 days of cooling volume. In the unlikely event the SCR/SSI elevation drops below normal elevations, make-up to SCR and/or rain-fall are likely to restore levels to normal.

The 7 day Completion Time is reasonable based on the low probability of an accident occurring during the 7 days that the level is low, the capability of the SSI to mitigate Design Basis Accidents at lower levels, and the time required to reasonably complete the Required Action.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the level cannot be restored to OPERABLE status within the associated Completion Time, or if the SSI is inoperable for reasons other than Condition A, 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 3.7.9.1

This SR verifies that adequate long term (30 day) cooling can be maintained. The specified level also ensures that sufficient NPSH is available to operate the SSWS pumps. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. This SR verifies that the SSI water level is ≥ 770 ft mean sea level.

SR 3.7.9.2

This SR verifies that the SSWS is available to cool the CCW System to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. This SR verifies that the water temperature of the Station Service Water System intake is ≤ 102ºF.

REFERENCES

1. FSAR, Sections 2.3, 2.4 and 9.2.5.

2. Regulatory Guide 1.27.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Filtration/Pressurization System (CREFS)

BASES

BACKGROUND

The CREFS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREFS consists of two independent, redundant trains that pressurize, recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CREFS train contains two filtration units: an emergency pressurization unit and an emergency filtration unit. Each filtration unit consists of a prefilter, high efficiency particulate air (HEPA) filters, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system, as well as demisters to remove water droplets from the air stream. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provides backup in case of failure of the main HEPA filter bank. In addition, the emergency pressurization units contain a demister and a heater to maintain the humidity of the incoming air below 70%.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CREFS is an emergency system wholly contained within the Control Room Air Conditioning System, parts of which operate during normal unit operations. Upon receipt of the actuating signal(s), normal air supply fans to the CRE are isolated, and the stream of ventilation air is provided by the emergency pressurization units and then recirculated through the emergency filtration units. The demisters and heaters in the emergency pressurization units remove any large particles in the air, and any entrained

(continued)

BASES

BACKGROUND (continued)

water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers. Continuous operation of each train's emergency pressurization unit for at least 10 hours per month, with the heaters on, reduces moisture buildup on the HEPA filters adsorbers. Both the demister and heater are important to the effectiveness of the charcoal adsorbers.

Actuation of the CREFS by a Safety Injection, Loss of Offsite Power or Intake Vent High Radiation signal places the system in the emergency recirculation mode. Actuation of the system to the emergency recirculation mode of operation, closes the unfiltered outside air supply path and the system exhaust dampers, stops normal supply and exhaust fans, and aligns the system for recirculation of the air within the CRE through the redundant trains of HEPA and the charcoal filters. The emergency recirculation mode also initiates pressurization and filtered ventilation of the air supply to the CRE.

Outside air is filtered, and added to the air being recirculated from the CRE. Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the surrounding areas adjacent to the CRE boundary.

The air entering the CRE is continuously monitored by radiation detectors. One detector output above the setpoint will cause actuation of the emergency recirculation mode.

A single CREFS train operating at a flow rate of < 800 cfm will pressurize the CRE to about 0.125 inches water gauge relative to external areas adjacent to the CRE boundary. The CREFS operation in maintaining the CRE habitable is discussed in the FSAR, Sections 2.2, 6.4, 6.5, 7.3, and 9.4 (Ref. 1).

Because the control room door ingress/egress is to a stairwell which is equivalent to a two-door vestibule, backflow will not occur with the CPSES CREFS design and the 10 cfm is not applicable per SRP 6.4. The ductwork has all welded joints which were leak tested prior to operation. Therefore, the assumed unfiltered inleakage from adjacent areas is conservative with respect to the SRP review criteria.

The Control Room Habitability is maintained by limiting the inleakage of potentially contaminated air into the Control Room Envelope. The potential leakage paths for the Control Room Envelope include the control room enclosure (e.g., walls, penetrations, floors, ceilings, joints, etc.), and other potential paths such as pressurized ductwork from other HVAC systems, pressurized air systems (e.g., instrument air) or isolated HVAC intakes.

(continued)

BASES

BACKGROUND (continued)

The periodic surveillance pressurization tests verify the integrity of the control room enclosure with respect to potentially contaminated adjacent areas in accordance with SRP 6.4. It does not verify filtered inleakage internal to the filtration units and ductwork nor does it veriy unfiltered inleakage from internal pressurized sources (e.g. instrument air). These sources of inleakage are addressed separately from TS surveillances.

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. The CREFS is designed in accordance with Seismic Category I requirements.

The CREFS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or its equivalent to any part of the body.

APPLICABLE SAFETY ANALYSES

The CREFS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CREFS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis accident, fission product release presented in the FSAR, Chapter 15 (Ref. 2).

The Control Room post accident mode of operation is the emergency recirculation mode. In the emergency recirculation mode, both the Emergency Filtration and Emergency Pressurization Units are functioning and they operate in series. In other words, all air which passes through the Emergency Pressurization Unit in each train will pass through the corresponding Emergency Filtration Unit before it is released into the Control Room. The safety analysis which confirmed the CREFS design took credit for no more than 99% filter efficiency of the Emergency Filtration Units only. If the Emergency Pressurization Units do not meet the surveillance requirement criteria for filtration the safety analyses and the associated acceptance criteria continue to be met by the Emergency Filtration Units. Thus, the operators will continue to be provided the protection identified in the licensing bases for CPSES.

The CREFS provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a

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APPLICABLE SAFETY ANALYSES (continued)

hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 1). The analysis for Comanche Peak has determined no CREFS actuation is required based on hazardous chemical releases or smoke and no Surveillance Requirements are required to verify operability based on hazardous chemicals or smoke.

The worst case single active failure of a component of the CREFS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The CREFS satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Two independent and redundant CREFS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of a large radioactive release.

Each CREFS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CREFS train is OPERABLE when both filtration units (i.e., the emergency pressurization unit (EPU) and emergency filtration unit (EFU)) are OPERABLE. A filtration unit is OPERABLE when the associated:

a. Fan is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions (the EFU must meet Ventilation Filter Testing Program (VFTP) requirements; the EPU must meet VFTP requirements, except for filtration requirements); and

c. Heater (EPU only), demister (EPU only), ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In order for the CREFS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBA's, and that CRE occupants are protected from hazardous chemicals and smoke.

(continued)

BASES

LCO (continued)

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, 6, and during movement of irradiated fuel assemblies the CREFS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

During movement of irradiated fuel assemblies the CREFS must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1

When one CREFS train is inoperable for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in loss of CREFS 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.

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

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

(continued)

ACTIONS

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

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protection measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CREFS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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

In MODE 5 or 6, or during movement of irradiated fuel assemblies, if the inoperable CREFS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CREFS train in the emergency mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the

(continued)

BASES

ACTIONS

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

CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

E.1 and E.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CREFS trains inoperable or with one or more CREFS trains inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

F.1

If both CREFS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable CRE boundary (i.e., Condition B), the CREFS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, each train once every month provides an adequate check of this system. Monthly heater operations dry out any moisture accumulated in the charcoal from humidity in the ambient air. Filtration units with heaters must be operated for $\geq$ 10 continuous hours with the heaters energized. Filtration units without heaters need only be operated for $\geq$ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy.

SR 3.7.10.2

This SR verifies that the required CREFS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREFS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 3). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency,

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.2 (continued)

minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

The VFTP filtration testing requirements of Sections 5.5.11a, b, and c are not required for an Emergency Pressurization Unit when being testing (1) during a periodic test (e.g., 18 months or after 720 hours of operation), (2) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (3) following painting, fire, or chemical release for the corresponding CREFS train to be OPERABLE.

SR 3.7.10.3

This SR verifies that each CREFS train starts and operates on an actual or simulated Safety Injection, Loss-of-Offsite Power, or Intake Vent-High Radiation actuation signal. The Frequency of 18 months is based on industry operating experience and is consistent with the typical refueling cycle. Each actuation signal must be verified (overlapping testing is acceptable).

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body and the CRE occupants are protected from hazardous chemicals and smoke. For Comanche Peak there is no CREFS actuation for hazardous chemical releases or smoke and there are no Surveillance Requirements that verify operability for hazardous chemicals or smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 4) which endorses, with

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.4 (continued)

exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 5). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 6). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. FSAR, Sections 2.2, 6.4, 6.5, 7.3, 9.4, and 9.5.

2. FSAR, Chapter 15.

3. Regulatory Guide 1.52.

4. Regulatory Guide 1.196.

5. NEI 99-03, “Control Room Habitability Assessment,” June 2001.

6. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694).

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Air Conditioning System (CRACS)

BASES

BACKGROUND

The control room for CPSES is common to both units and the CRACS is a shared system common to both units.

The CRACS provides temperature control for the control room during normal and emergency operation.

The CRACS consists of two redundant trains that provide cooling and heating of recirculated control room air. Each CRACS train includes two heating and cooling units, instrumentation, and controls to provide for control room temperature control. Each cooling unit provides 50% of the maximum heat removal capability for its respective Train. The CRACS is a subsystem providing air temperature control for the control room.

The CRACS is an emergency system, parts of which may also operate during normal unit operations. A single train will provide the required temperature control to maintain the control room between 70ºF and 80ºF. The CRACS operation in maintaining the control room temperature is discussed in the FSAR, Sections 6.4 (Ref. 1) and 9.4.1 (Ref. 2).

The CRACS heat load during and after an accident would be less than during normal conditions whenever the outdoor temperature is greater than 80ºF since the intake flow rate is reduced. However, the cooling water temperature increases due to the accident heat load and resulting increase in the temperature of the Ultimate Heat Sink.

If one 50% safety related cooling unit in a train is inoperable, the train may still be operable if an evaluation of the conditions (e.g. weather, UHS temperature, etc.) show that one 50% unit is capable of performing the function for thirty days or that the inoperable unit(s) can be restored prior to conditions that would require two 50% units. During conditions when two units are required per train to maintain design temperatures and one unit is inoperable, the train is inoperable; however, if at least one 50% safety related cooling unit in each train is operable with required cooling water and power, 100% of the heat removal capability is still available.

APPLICABLE SAFETY ANALYSES

The design basis of the CRACS is to maintain the control room temperature for 30 days of continuous occupancy.

The CRACS components are arranged in redundant, safety related trains.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

During normal and emergency operation, the CRACS maintains the temperature between 70ºF and 80ºF. A single active failure of a component of the CRACS, with a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The CRACS is designed in accordance with Seismic Category I requirements. The CRACS is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

The CRACS satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the CRACS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The CRACS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both trains. These components include the cooling coils and associated temperature control instrumentation. In addition, the CRACS must be operable to the extent that air circulation can be maintained. The CRACS heating coils are not required for OPERABILITY.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of irradiated fuel assemblies, the CRACS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements.

ACTIONS

A.1

With one CRACS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CRACS train is adequate to maintain the control room temperature within limits.

However, the overall reliability is reduced because a single failure in the OPERABLE CRACS train could result in loss of CRACS function. The 30 day Completion Time is based on the low probability of an event challenging the remaining units and the consideration that the remaining train can provide the required protection.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable CRACS train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. 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.

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

In MODE 5 or 6, and during movement of irradiated fuel, if the inoperable CRACS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CRACS train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that active failures will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the 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 and D.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CRACS trains inoperable and at least 100% of the required heat removal capability equivalent to a single OPERABLE train available, action must be taken to restore OPERABLE status in 30 days. In this condition, the remaining OPERABLE air conditioning units in both trains are adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CRACS air conditioning units could result in loss of CRACS function. The 30 day Completion Time is based on the low probability of an event challenging the remaining units and the consideration that the remaining train can provide the required protection.

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If both CRACS trains are inoperable in MODE 1, 2, 3, or 4, with at least 100% of the required heat removal capability equivalent to a single OPERABLE train available, action must be taken to restore OPERABLE status in 30 days. In this condition, the remaining OPERABLE air conditioning units in both trains are adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CRACS air conditioning units could result in loss of CRACS function. The 30 day Completion Time is based on the low probability of an event challenging the remaining units and the consideration that the remaining train can provide the required protection.

If both CRACS trains are inoperable in MODE 1, 2, 3, or 4, the control room CRACS may not be capable of performing its intended function. Therefore, as an alternative to Required Action E.1, LCO 3.0.3 may be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the safety analyses in the control room. This SR consists of a combination of testing and calculations. The 18 month Frequency is appropriate since significant degradation of the CRACS is slow and is not expected over this time period. The CRACS heating coils are not required to be included in this SR.

REFERENCES

1. FSAR, Section 6.4.

2. FSAR, Section 9.4.1.

B 3.7 PLANT SYSTEMS

B 3.7.12 Primary Plant Ventilation System (PPVS) - ESF Filtration Trains

BASES

BACKGROUND

The Primary Plant Ventilation System (PPVS) serves all the areas housing engineered safety features equipment which recirculate post-accident reactor coolant outside containment after LOCA as well as the radwaste areas and the fuel handling and storage areas. The PPVS supply consists of eight non-safety related, primary plant supply fans (30,000 scfm each) sharing common ductwork and dampers and two non-safety related, ventilation equipment room supply fans. The PPVS exhaust consists of twelve non-ESF filtration units and fans (15,000 scfm each), four ESF filtration units and fans (15,000 scfm each), and two non-safety related, ventilation equipment room exhaust fans. The exhaust units are run during normal conditions to provide a slightly negative pressure in the primary plant areas.

The PPVS supply fans provide cooling air during normal operation. The non-ESF exhaust filtration units filter air from each units Safeguards building and from the common Auxiliary and Fuel buildings during normal operation. The PPVS exhaust ESF Filtration units filter air from these areas which contain the active ECCS components during the recirculation phase of a loss of coolant accident (LOCA). The ESF filtration units may be used in normal operation if the capacity of the non-ESF units is insufficient for a condition (e.g., maximum outdoor design conditions) or a mode (e.g., containment purge) or if a non-ESF unit is unavailable.

The PPVS exhaust consists of two electrically independent and redundant trains sharing common ductwork and plenums. Each train has six non-ESF Filtration units and two ESF Filtration units. Each ESF Filtration unit consists of a heater, a demister, a high efficiency particulate air (HEPA) filter, 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, as well as demisters functioning to reduce the relative humidity of the air stream. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provide backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the accident analysis, but serves to collect charcoal fines, and to back up the upstream HEPA filter should it develop a leak. The system initiates filtered ventilation of the Safeguards, Auxiliary and Fuel buildings following receipt of a safety injection (SI) signal from either unit.

The PPVS is a normally operating system, aligned to bypass the ESF HEPA filters and charcoal adsorbers. During emergency operations, the PPVS

(continued)

BASES

BACKGROUND (continued)

non-ESF fans are stopped and ESF fans are started to begin filtration. Upon receipt of the actuating signal, the stream of ventilation air discharges through the ESF filter trains. The demisters remove any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The PPVS is discussed in the FSAR, Sections 6.5.1, 9.4.5, and 15.6.5 (Refs. 1, 2, and 3, respectively) since it may be used for normal, as well as post accident, atmospheric cleanup functions. The primary purpose of the heaters is to maintain the relative humidity at an acceptable level, consistent with iodine removal efficiencies per Regulatory Guide 1.52 (Ref. 4).

APPLICABLE SAFETY ANALYSES

The design basis of the PPVS is established by the large break LOCA. The system evaluation assumes a continuous 1 gpm leak from the system recirculating primary reactor coolant outside containment post-LOCA for 30 days. The system limits the radioactive release due to ESF equipment leakage such that the total release, including containment leakage, is within the 10 CFR 100 (Ref. 5) and GDC-19 (Ref. 7) limits. Although not specifically analyzed, the system is also credited with the mitigation of a passive failure of the ECCS outside containment, such as an SI or RHR pump seal failure, during the recirculation mode. The analysis of the effects and consequences of a large break LOCA is presented in Reference 3. The PPVS also actuates following a small break LOCA, in those cases where the ECCS goes into the recirculation mode of long term cooling, to clean up releases of smaller leaks, such as from valve stem packing.

The PPVS satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the PPVS are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train coincident with loss of offsite power. Total system failure could result in the atmospheric release from the ESF equipment leakage exceeding regulatory limits in the event of a Design Basis Accident (DBA).

PPVS is considered OPERABLE when the individual components necessary to maintain the ESF filtration are OPERABLE in both trains.

A PPVS Train is considered OPERABLE when it's individual components necessary to maintain the ESF filtration are operable such that the required negative pressure can be maintained in the Auxiliary and Safeguards

(continued)

BASES

LCO (continued)

buildings. Note: If one of the two ESF filtration units in a train can maintain the required negative pressure alone, it would satisfy the operability requirements provided:

1. The out of service/inoperable unit is isolated or the exhaust fan is prevented from automatic starting to ensure that no unfiltered exhaust to the environment occurs, and,

2. If the OPERABLE filter unit in a train is CPX-VAFUPK-15 or 16 the exhaust fan of the out of service/inoperable unit shall be prevented from starting or placed under administrative control to secure the fan in the event of an actual ESF actuation. This will ensure the fan room design heat loads are not exceeded.

3. Surveillance Requirement 4.7.12.4 has been satisfactorily performed within the required interval, in <u>the one unit per train configuration</u> for the particular unit concern in order to demonstrate the negative pressure function.

A PPVS ESF Filtration Unit is considered OPERABLE when its associated:

a. Fan is OPERABLE;

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

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the PPVS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODE 5 or 6, the PPVS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

In MODE 5 or 6 or during movement of irradiated fuel assemblies, the PPVS is not required to be operable since it is not required for mitigation of fuel handling accidents [Ref. 3].

(continued)

BASES (continued)

ACTIONS

A.1

With one or more ESF Filtration trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel buildings ≥ 0.05 inch water gauge, action must be taken to restore OPERABLE status within 30 days. During this time the ESF Filtration trains must maintain ≥ 0.01 inch water gauge. This negative pressure will still ensure that unfiltered air does not escape the pressure envelope.

The 30 day Completion Time is appropriate because an adequate negative pressure envelope is still maintained.

B.1

With one or more ESF Filtration trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings ≥ 0.01 inch water gauge, action must be taken to restore OPERABLE status within 7 days.

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period and the design of the buildings included within the negative pressure envelope. The buildings are designed such that the rooms with sources of potential ECCS leakage are below grade or internal to the structure of these buildings thus providing a buffer zone to external leakage.

C.1

With one PPVS train inoperable, for any reason except failure to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings ≥ 0.05 inch water gauge, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the PPVS function.

Due to the layout of the ESF equipment interior to the Auxiliary and Safeguard buildings and the design of the PPVS supply and exhaust, failure to maintain the required negative pressure does not constitute a loss of the safety function and action A.1 would not apply. As long as air flow is achievable, essentially all ESF leakage would be filtered and exhausted by the PPV.

(continued)

BASES

ACTIONS

C.1 (continued)

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

Concurrent failure of two PPVS trains would result in the loss of functional capability; therefore, LCO 3.0.3 must be entered immediately.

D.1 and D.2

If the PPVS train or negative pressure envelope cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once a month provides an adequate check on this system. Monthly heater operations dry out any moisture that may have accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated ≥ 10 continuous hours with the heaters energized with flow through the HEPA filters and charcoal adsorbers. Operation is to be initiated from the Control Room. The 31 day Frequency is based on the known reliability of equipment and the two train redundancy available.

SR 3.7.12.2

This SR verifies that the required PPVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The ECCS PREACS filter tests are in accordance with Reference 4. The VFTP includes testing HEPA filter performance, charcoal adsorbers efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.3

This SR verifies that each PPVS train starts and operates on an actual or simulated Safety Injection actuation signal. The 18 month Frequency is consistent with that specified in Reference 4.

SR 3.7.12.4

This SR verifies the integrity of the negative pressure envelope. The ability of the Auxiliary and Safeguards buildings to maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper functioning of the PPVS. During the post accident mode of operation, the PPVS is designed to maintain a slight negative pressure in the Auxiliary, Fuel and Safeguards buildings, with respect to adjacent areas, to prevent unfiltered LEAKAGE. The acceptance criteria of ≤ -0.05 inches water gauge relative to atmospheric pressure was selected as a reasonable measure of the integrity of the negative pressure boundary. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 6).

This test is conducted with the tests for filter penetration; thus, an 18 month Frequency on a STAGGERED TEST BASIS is consistent with that specified in Reference 4.

SR 3.7.12.5

Not used.

SR 3.7.12.6

This SR is required to verify the shutdown of the non-ESF fans to prevent bypass of the ESF Filtration units. The plant design does not include bypass dampers, however, bypass of the filter units will occur if the non-ESF fans are still running when the ESF fans start. Therefore, to prevent bypass, the non-ESF fans must be stopped. The SR demonstrates that the non-ESF fans stop on an actual or simulated ESF actuation signal (safety injection signal). Verification of the tripping of each non-ESF fan on an SI signal is necessary to ensure that the system functions properly. A frequency of 18 months is consistent with SR 3.7.12.3.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.5.1.
2. FSAR, Section 9.4.3 and 9.4.5.
3. FSAR, Chapter 15.
4. Regulatory Guide 1.52 (Rev. 2).
5. 10 CFR 100.11.
6. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.
7. 10 CFR 50, Appendix A, GDC-19.

B 3.7 PLANT SYSTEMS

B 3.7.13 FUEL BUILDING AIR CLEANUP SYSTEM (FBACS)

BASES

NOT USED

B 3.7 PLANT SYSTEMS

B 3.7.14 PENETRATION ROOM EXHAUST AIR CLEANUP SYSTEM (PREACS)

BASES

NOT USED

B 3.7 PLANT SYSTEMS

B 3.7.15 Fuel Storage Area Water Level

BASES

BACKGROUND

The minimum water level in a fuel storage area meets the assumptions 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.

The minimum water depth for design for fuel handling ensures that a nominal 23 feet of water is maintained above the top of a damaged fuel assembly laying atop the fuel storage racks and that 10 feet of water shielding is maintained above fuel assemblies being moved.

The fuel storage areas in the Fuel Building include the two spent fuel pools (Spent Fuel Pool No. 1 and Spent Fuel Pool No. 2). In addition, the fuel storage areas include a portion of the Refueling Cavity in each Containment Building Permanent spent fuel storage racks are located in each spent fuel pool and in the upender area of the Refueling Cavity in each containment. Maintaining 23 feet of water over these storage racks also ensures a nominal depth of 23 feet above the top of structures in the transfer canal and wet cask pit during fuel movement. A general description of the fuel storage pool design is given in the FSAR, Section 9.1.2 (Ref. 1). The in-containment fuel storage area is described in FSAR Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the FSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the FSAR, Section 15.7.4 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in a fuel storage area meets the pool decontamination factor of 200 assumptions of the fuel handling accident described in Regulatory Guide 1.195 (Ref. 4). The resultant 2 hour thyroid dose per person at the exclusion area boundary is well within the 10 CFR 100 (Ref. 5) limits [Reference 6 and 7].

According to Reference 4, there should be a nominal 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 4 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle. To offset this small nonconservatism, the analysis

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

assumes that all fuel rods fail, although analysis shows that only the first few rows fail from a hypothetical maximum drop. The fuel storage pool water level satisfies Criteria 2 and 3 of 10CFR50.36(c)(2)(ii).

LCO

The fuel storage area water level is required to be ≥ 23 ft over the top of the storage racks. 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 storage areas.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel storage areas, 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 prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel storage areas water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel storage areas is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. 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, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the fuel storage pool must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1 (continued)

During refueling operations, the level in the fuel storage pool is checked daily in accordance with SR 3.9.7.1.

REFERENCES

1. FSAR, Section 9.1.2.
2. FSAR, Section 9.1.3.
3. FSAR, Section 15.7.
4. Regulatory Guide 1.195, May 2003.
5. 10 CFR 100.11.
6. WCAP-7518-L, Radiological consequences of a Fuel Handling Accident, June 1970.
7. NUREG-0800, Section 15.7.4.

B 3.7 PLANT SYSTEMS

B 3.7.16 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

A common Fuel Building houses facilities for storage and transfer of new and spent fuel. Two pools are provided for CPSES spent fuel storage. Each pool may be used to store fuel from either or both of the CPSES units.

In the Region II rack (References 1 and 2) design, the spent fuel storage pool numbers 1 and 2 (SFP1 and SFP2) permit four different configurations (as shown in Figure 3.7.17-4) which, for the purpose of criticality considerations, are considered as separate pools. Region II racks, with 1462 and 1470 storage positions in SFP1 and SFP2 respectively (2932 total), are designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups and decay times within either (1) the “acceptable” domain of Figure 3.7.17-1 in a 4 out of 4 configuration, (2) the “acceptable” domain of Figure 3.7.17-2 in a 3 out of 4 configuration, (3) the “acceptable” domain of Figure 3.7.17-3 in a 2 out of 4 configuration, or (4) a 1 out of 4 configuration as shown in Figure 3.7.17-4.

Region I racks (References 1 and 2) with 222 and 219 storage positions located in SFP1 and SFP2 respectively (441 total), constitute a fifth configuration within the pools. These Region I racks are designed to accommodate new fuel with a maximum enrichment of 5.0 w/t % U-235 or spent fuel regardless of the discharge fuel burnup or decay time. Soluble boron is not credited for the storage of spent fuel assemblies within the Region I racks, and there are no storage pattern restrictions associated with the Region I racks. The neutron absorber material Boral is credited for the storage of spent fuel assemblies within the Region I racks to maintain k_{eff} less than or equal to 0.95.

Soluble boron is not credited for the storage of fuel assemblies within the Region II racks in the 1 out of 4 and 2 out of 4 configurations. Criticality analyses have been performed (Reference 2) which demonstrate that the multiplication factor, k_{eff}, of the fuel and spent fuel storage racks is less than or equal to 0.95.

In order to maintain k_{eff} less than or equal to 0.95, the presence of fuel pool soluble boron is credited for the storage of fuel assemblies within the Region II racks in the 3 out of 4 and 4 out of 4 configurations. A description of how credit for fuel storage pool soluble boron is used under normal storage configuration conditions is found in References 2, 3, and 4. The storage configuration is defined using calculations to ensure that k_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including

(continued)

BASES

BACKGROUND (continued)

tolerances and uncertainties. Soluble boron credit is then used to maintain k_{eff} less than or equal to 0.95. Criticality analyses have been performed (Reference 3) which demonstrate that the pools require 800 ppm of soluble boron to maintain k_{eff} less than or equal to 0.95 for all allowed combinations of storage configurations, enrichments, burnups, and decay time limits. The effect of B-10 depletion on the boron concentration for maintaining k_{eff} less than or equal to 0.95 is negligible.

Criticality analyses considering accident conditions have also been performed (References 2 and 3). These analyses establish the amount of soluble boron necessary to ensure that k_{eff} will be maintained less than or equal to 0.95 should pool temperatures fall outside the assumed range or a fuel assembly misload occur. The total amount of soluble boron required to mitigate these events is 1900 ppm.

For an occurrence of the above postulated accident condition, the double contingency principle of ANSI/ANS 8.1-1983 (Reference 6) can be applied. This states that one is not required to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident. Thus, for these postulated accident conditions, the presence of additional soluble boron in the storage pool water (above the concentration required for normal conditions and reactivity equivalencing) can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event.

A boron concentration equal to or greater than 2000 ppm assures that a dilution event which will result in a k_{eff} greater than 0.95 is not credible. This is demonstrated by a boron dilution analysis performed for the CPSES Spent Fuel pools. This conclusion is based on the following: (1) a substantial amount of water is needed in order to dilute the SFP to the design k_{eff} of 0.95, (2) since such a large water volume turnover is required, a SFP dilution event would be readily detected by plant personnel via alarms, flooding in the fuel and auxiliary buildings or by normal operator rounds through the SFP area, and (3) evaluations indicate that, based on the flow rates of non-borated water normally available to the SFP, taken in conjunction with significant operator errors, and equipment failures, sufficient time is available to detect and respond to a dilution event. In addition, there is significant conservatism built into this evaluation; for example, the cooling of the spent fuel pools can be performed by one train supplying common water to both pools. This cooling configuration would allow credit of the volume of both pools and substantially increase the dilution time estimates presented. However, because the flexibility exists for the cooling system to be totally dedicated to one pool, only one pool volume is considered in this evaluation.

(continued)

BASES

BACKGROUND (continued)

It should be noted that this boron dilution evaluation considered the boron dilution volumes required to dilute the SFP from 1900 ppm to 800 ppm. The 800 ppm end point was utilized to ensure that k_{eff} for the spent fuel racks would remain less than or equal to 0.95. However, as discussed above, calculations for Region II 3 out of 4 and 4 out of 4 configurations have been performed on a 95/95 basis to show that the spent fuel rack k_{eff} remains less than 1.0 with non-borated water in the pool. Thus, even if the SFP were diluted to concentrations approaching zero ppm, the fuel in the Region II racks would remain subcritical and the health and safety of the public would be protected.

The storage of fuel with initial enrichments up to and including 5.0 weight percent U-235 in the Comanche Peak fuel storage pools has been evaluated. For the Region II storage racks, the resulting enrichment, burnup, and decay time limits for the pool are shown in Figures 3.7.17-1 through 3.7.17-4.

APPLICABLE SAFETY ANALYSES

Most fuel storage pool accident conditions will not result in a significant increase in k_{eff}. Examples of such accidents are the drop of a fuel assembly on top of a rack, and the drop of a fuel assembly outside but adjacent to the rack modules.

A dropped assembly accident occurs when a fuel assembly is dropped onto the storage racks. The rack structure is not excessively deformed. An assembly, in its most reactive condition, is considered in the criticality evaluation. Accident analyses have been performed which demonstrate that the dropped assembly which comes to rest horizontally on top of the rack has sufficient water separating it from the active fuel height of stored assemblies to preclude neutronic interaction. This is true even with unborated water. For the borated water condition, the potential for interaction is even less since the water contains boron which is an additional thermal neutron absorber.

However, three accidents can be postulated for each storage configuration that could increase reactivity beyond the analyzed condition. The first postulated accident would be a change in pool temperature to outside the range of normal operating temperatures assumed in the criticality analyses (50ºF to 150ºF). The second accident would be dropping a fuel assembly into an already loaded cell. The third would be the misloading of a fuel assembly within the racks into a cell for which the restrictions on location, enrichment, burnup, or decay time are not satisfied or adjacent to but outside the racks.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Variations in the temperature of the water passing through the stored fuel assemblies outside the normal operating range were considered in the criticality analysis. The reactivity effects of a temperature range from 32ºF to 212ºF were evaluated. The increase in reactivity due to the change in temperature is bounded by the misloading accident.

For the accident of dropping a fuel assembly into an already loaded cell, the upward axial leakage of that cell will be reduced; however, the overall effect on the rack reactivity will be insignificant. This is because minimizing the upward-only leakage of just a single cell will not cause any significant increase in reactivity. Furthermore, the neutronic coupling between the dropped assembly and the already loaded assembly will be low due to several inches of assembly nozzle structure which would separate the active fuel regions. Therefore, this accident would clearly be bounded by the misloading accident.

The fuel assembly misloading accident involves placement of a fuel assembly in a location for which it does not meet the requirements for enrichment, burnup, or decay time including the placement of an assembly in a location that is required to be left empty. The result of the misloading is to add positive reactivity, increasing k_{eff} toward 0.95. The maximum required boron to compensate for this event is 1900 ppm, which is below the LCO limit of 2000 ppm.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of the 10CFR50.36(c)(2)(ii).

LCO

The fuel storage pool boron concentration is required to be ≥ 2000 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential criticality accident scenarios as described in Reference 5. The amount of soluble boron required to offset each of the above postulated accidents was evaluated for all of the proposed storage configurations. The specified minimum boron concentration of 2000 ppm assures that the concentration will remain above these values.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

When the concentration of boron in the fuel storage 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 action is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This requirement does not preclude movement of a fuel assembly to a safe position.

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply. If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. 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 sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

REFERENCES

1. FSAR, Section 9.1.

2. License Amendment Requests 94-22, 98-08, and 00-05, Spent Fuel Storage Capacity Increase, Docket NOS 50-445 and 50-446, CPSES.

3. Comanche Peak High Density Spent Fuel Rack Criticality Analysis using Soluble Boron Credit and No Outer Wrapper Plate, dated July, 2001 (Enclosure 2 to TXX-01118).

4. WCAP-14416 NP-A, Rev. 1, “Westinghouse Spent Fuel Rack Criticality Analysis Methodology,” November 1996.

5. FSAR, Section 15.7.4.

6. American Nuclear Society, “American National Standard for Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors,” ANSI/ANS-8.1-1983, October 7, 1983.

B 3.7 PLANT SYSTEMS

B 3.7.17 Spent Fuel Assembly Storage

BASES

BACKGROUND

A common Fuel Building houses facilities for storage and transfer of new and spent fuel. Two pools are provided for CPSES spent fuel storage. Each pool may be used to store fuel from either or both of the CPSES units.

In the Region II rack (References 1 and 2) design, the spent fuel storage pool numbers 1 and 2 (SFP1 and SFP2) permit four different configurations (as shown in Figure 3.7.17-4) which, for the purpose of criticality considerations, are considered as separate pools. Region II racks, with 1462 and 1470 storage positions in SFP1 and SFP2 respectively (2932 total), are designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups and decay times within either (1) the "acceptable" domain of Figure 3.7.17-1 in a 4 out of 4 configuration, (2) the "acceptable" domain of Figure 3.7.17-2 in a 3 out of 4 configuration, (3) the "acceptable" domain of Figure 3.7.17-3 in a 2 out of 4 configuration, or (4) a 1 out of 4 configuration as shown in Figure 3.7.17.4.

Region I racks (References 1 and 2) with 222 and 219 storage positions located in SFP1 and SFP2 respectively (441 total) constitute a fifth configuration within the pools. These Region I racks are designed to accommodate new fuel with a maximum enrichment of 5.0 w/t % U-235 or spent fuel regardless of the discharge fuel burnup. Soluble boron is not credited for the storage of spent fuel assemblies within the Region I racks, and there are no storage pattern restrictions associated with the Region I racks. The neutron absorber material Boral is credited for the storage of spent fuel assemblies within the Region I racks to maintain k_{eff} less than or equal to 0.95.

A discussion of how soluble boron is credited for the storage of spent fuel assemblies is contained in the BACKGROUND for B 3.7.16.

Within the SFP1 Region II racks, there exist two oversized (2x2) cells. Within the SFP2 Region I racks, there exists one oversized (2x2) cell. These oversized cells are not approved for storage of either fresh or spent fuel. However, they can be used as a place in the pool for an assembly to be lowered and raised while being inspected. Prior to use of the inspection cells certain prerequisites must be met. Criticality analyses (Reference 3) have been performed which demonstrate that there is no increase in reactivity relative to the approved Region II storage configurations (the current licensing basis requirements for the spent fuel pool are still met) provided that administrative prerequisites are maintained for the oversized cells in

(continued)

BASES

BACKGROUND (continued)

SFP1 Region II racks. The prerequisite for the use of the oversized cells in Region II racks is that all the Region II cells in the first row surrounding the oversized cell remain empty. This results in a total of 8 empty Region II cells adjacent to the oversized cell in the SFP I Region II rack adjacent to the Region I rack and a total of 5 empty Region II cells adjacent to the oversized cell in the SFP1 Region II racks adjacent to the spent fuel pool walls. There are no prerequisites for the use of the oversized cell in SFP2 Region I racks since the criticality analyses (Reference 3) demonstrate there is no increase in reactivity relative to the approved Region I storage configuration.

APPLICABLE SAFETY ANALYSES

A discussion of the criticality analysis for the storage of spent fuel assemblies is contained in the APPLICABLE SAFETY ANALYSES for B 3.7.16.

Most fuel storage pool accident conditions will not result in a significant increase in k_{eff}. Examples of such accidents are the drop of a fuel assembly on top of a rack, and the drop of a fuel assembly outside but adjacent to the rack modules. However, accidents can be postulated for each rack storage configuration which could increase reactivity beyond the analyzed condition. A discussion of these accidents is contained in B 3.7.16.

By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents may be limited to a small fraction of the total operating time.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The restrictions on the placement of fuel assemblies within the spent fuel pool, in accordance with Figures 3.7.17-1 through 3.7.17-4, in the accompanying LCO, ensures the k_{eff} of the spent fuel storage pool will always remain ≤ 0.95, assuming the pool to be flooded with borated water.

NOTE: The oversized inspection cells within the racks are not approved storage locations and are not covered by the LCO. Administrative controls which govern the use of the inspections cells are described in the BACKGROUND.

(continued)

BASES (continued)

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in Region II racks of the fuel storage pool.

ACTIONS

A.1

When the configuration of fuel assemblies stored in Region II racks of the spent fuel storage pool is not in accordance with Figures 3.7.17-1 through 3.7.17-4, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figures 3.7.17-1 through12 3.7.17-4.

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

This SR verifies, by administrative means, that the initial enrichment, burnup and decay time of the fuel assembly is in accordance with Figures 3.7.17-1 through 3.7.17-4 in the accompanying LCO.

REFERENCES

1. FSAR Section 9.1.

2. License Amendment Request 94-22, 98-08, and 00-05 Spent Fuel Storage Capacity Increase, Docket Nos. 50-445 and 50-446, CPSES.

3. Criticality Safety Analysis of Holtec Spent Fuel Racks, dated January, 2003 (Holtec Report HI-2002436, Revision 9).

B 3.7 PLANT SYSTEMS

B 3.7.18 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed a small fraction of the unit EAB limits (Ref. 1) for whole body and thyroid dose rates.

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs. The Auxiliary Feedwater System supplies the necessary makeup to the steam generators.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Secondary specific activity limits satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 1).

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 depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the 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 3.7.18.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident

(continued)

BASES

SURVEILLANCE REQUIREMENTS)

SR 3.7.18.1 (continued)

releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 100.11.
2. FSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.19 Safety Chilled Water System

BASES

BACKGROUND

The Safety Chilled Water System provides essential chilled water to the emergency fan coil units (EFCUs) during normal and accident conditions. EFCUs are provided in motor-driven ESF pump rooms (i.e., Centrifugal Charging Pump rooms, Safety Injection Pump rooms, Residual Heat Removal (RHR) Pump rooms, Containment Spray Pump rooms, and the motor-driven Auxiliary Feedwater (AFW) Pump rooms), in the Spent Fuel Pool Cooling Pump rooms, in the Component Cooling Water (CCW) Pump rooms, in the UPS Rooms, and in the Class 1E electrical switchgear rooms. The system is designed to provide chilled water to maintain the ambient air temperature within the design limits of the essential equipment served by the system.

The safety related equipment and respective EFCUs are of the same safety train as the associated chilled water train. Thus, a power failure or other single failure to one cooling system train will not prevent the cooling of redundant equipment in the other train.

The Safety Chilled Water System for each unit consists of two separate and completely redundant safety trains. Each train consists of one packaged centrifugal chiller, one centrifugal chilled water recirculation pump, interconnecting piping, valves, controls and instrumentation. There are no automatic valves in the system. Additionally, the two trains share a common chilled water surge (expansion) tank, partitioned in the middle into two separate compartments to provide complete separation of the two trains, that function to ensure sufficient net positive suction head is available.

In addition to manual start capability, automatic start of the Safety Chill Water System is provided on a Safety Injection (SI) signal or a station blackout.

The Safety Chilled Water System is seismic Category I and remains operational during and after a safe shutdown earthquake. The associated instrumentation is described in greater detail in FSAR Sections, 7.3 and 9.4, References 1 and 2 respectively.

APPLICABLE SAFETY ANALYSES

The design basis of the Safety Chilled Water System is to support EFCUs that maintain air temperatures as required in selected rooms containing safety-related equipment during normal operation and during and after a design basis accident (with or without a loss of offsite power) or a blackout (loss of offsite power, LOOP).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Safety Chilled Water System is designed to perform its function in response to an SI signal with a single failure of any active component, assuming the loss of offsite power. One train of the Safety Chilled Water System provides 100% of the required cooling for the associated train of EFCUs.

The Safety Chilled Water System satisfies criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

Two Safety Chilled Water System trains are required OPERABLE to provide the required redundancy to ensure that the system functions to remove heat from the EFCUs during and after an accident assuming the worst case single failure occurs coincident with the loss of offsite power.

A Safety Chilled Water System train is considered OPERABLE when the associated chiller, chilled water pump, surge tank, piping, valves, and instrumentation required to perform the safety-related function are OPERABLE.

The isolation of Safety Chilled Water from the EFCUs may render those units inoperable but does not affect the OPERABILITY of the Safety Chilled Water System.

APPLICABILITY

In MODES 1, 2, 3, and 4 the Safety Chilled Water System is a normally operating system, which must be prepared to provide a safety-related cooling function consistent with the OPERABILITY requirements of the essential equipment it supports.

In MODE 5 or 6, the OPERABILITY requirements of the Safety Chilled Water System are determined by the systems it supports.

ACTIONS

A. 1

If one Safety Chilled Water System train is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE Safety Chilled Water System train is adequate to perform the heat removal function for its associated essential equipment.

However, the overall reliability is reduced because a single failure in the

(continued)

BASES

ACTIONS

A. 1 (continued)

OPERABLE Safety Chilled Water System train could result in loss of the Safety Chilled Water System function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time.

B.1 and B.2

If the Safety Chilled Water System train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and 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 3.7.19.1

This SR is modified by a Note indicating that the isolation of safety chilled water flow to individual components may render these components inoperable but does not affect the OPERABILITY of safety chilled water system.

Verifying the correct alignment for manual valves servicing safety-related equipment provides assurance that the proper flow paths exist for Safety Chilled Water System 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 being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

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

SR 3.7.19.2

This SR verifies proper operation of the Safety Chilled Water System fans and pumps on an actual or simulated Safety Injection actuation signal. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month Frequency. Therefore, the 18 month frequency is acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 7.3.
2. FSAR, Section 9.4.

B 3.7 PLANT SYSTEMS

B 3.7.20 UPS HVAC System - Operating

BASES

BACKGROUND

The UPS HVAC System provides temperature control for the safety related UPS & Distribution rooms during all normal and accident conditions.

The UPS HVAC System consists of:

a. A dedicated UPS Room Emergency Fan Coil Unit (EFCU) in each safety-related UPS & Distribution Room, and

b. Two electrically independent and redundant A/C trains either of which can support all four safety related UPS & Distribution rooms. Each train consists of an air conditioning unit. Ductwork, dampers, and instrumentation also form part of the system.

The UPS HVAC System is a normally operating system. Each EFCU normally provides the required temperature control to maintain its respective room below 104ºF during normal plant conditions. A single A/C train will also provide the required temperature control to maintain the UPS & Distribution rooms between 40ºF and 104ºF during normal plant conditions. Upon receipt of an actuating signal, a standby train would start.

The UPS HVAC System is also an emergency system. Each EFCU would provide the required temperature control to maintain its respective room below 122ºF during emergency conditions. A single A/C Train will also provide the required temperature control to maintain the UPS rooms below 122ºF during emergency plant conditions.

The control circuit design of the EFCUs does not include an "auto" start or "standby" feature. Each UPS Room Emergency Fan Coil Unit is controlled from a local control panel integral to the unit. The control panel contains a maintained two position hand switch (run/off). Each unit is directly wired to its associated safeguards bus and therefore, load shed if the bus is de-energized upon a Blackout signal ("BOS") or a Safety Injection ("S") signal. The units automatically restart upon re-energizing of the associated safeguards bus. An EFCU must be operating to be operable.

In the event an EFCU is inoperable and the respective A/C Train is also inoperable, 100% cooling can be provided by the opposite train's A/C Train.

In the event an EFCU for one or more rooms is inoperable and neither A/C Train is operable, the fans associated with the A/C Trains can circulate air

(continued)

BASES

BACKGROUND (continued)

from rooms serviced by the operable EFCUs. This is acceptable as long as temperatures are maintained within design limits.

The UPS HVAC System operation in maintaining the UPS inverter room temperatures is discussed in the FSAR, Section 9.4C.8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the UPS HVAC System is to maintain the UPS & Distribution room temperatures.

The UPS Rooms are dedicated to the UPS Unit and Train they support. The UPS A/C Train components are arranged in redundant, safety related trains. During emergency operation, the UPS HVAC System maintains the temperature below 122ºF. A single active failure of a component of the UPS HVAC, with a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant controls are provided for UPS room temperature control. The UPS HVAC is designed in accordance with Seismic Category I requirements. The UPS HVAC is capable of removing sensible and latent heat loads from the UPS inverter rooms, which include consideration of equipment heat load requirements to ensure equipment OPERABILITY.

The UPS HVAC satisfies Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

Two UPS HVAC System trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove heat from the UPS rooms during a DBA. A UPS HVAC System train is considered OPERABLE when its associated:

a. UPS Emergency Fan Coil Unit is OPERABLE, or

b. 1. Air Conditioner and fans are OPERABLE, and

   2. Ductwork and dampers are OPERABLE, and air circulation can be maintained.

APPLICABILITY

In MODE 1, 2, 3, or 4, the UPS HVAC System is required to be OPERABLE to ensure the UPS & Distribution room temperatures will not exceed equipment operational requirements.

(continued)

BASES

APPLICABILITY (continued)

In MODE 5 or 6, the OPERABILITY requirements of the UPS HVAC System are determined by the systems it supports.

ACTIONS

A.1 and A.2

With one UPS HVAC System train (i.e., EFCU and A/C Train of the same electrical train) inoperable, action must be taken immediately to verify the A / C Train of the opposite electrical train is operable and to restore OPERABLE status within 30 days. During this period, the remaining OPERABLE train is adequate to perform the UPS HVAC System function. The 30 day Completion Time is based on the risk from an event occurring requiring the inoperable UPS HVAC Train, and the remaining UPS A/C Train providing the required protection.

B.1, B.2 and B.3

With one or more EFCUs and both UPS A/C trains inoperable, action must be taken immediately to verify air circulation is being maintained and that the temperatures are being maintained within equipment design limits. The maximum temperature limit for these rooms is provided in the TRM. The 12 hour completion time for reverification of temperatures is considered reasonable based on slow rates of changes during steady state conditions. The 72 hour Completion Time is based on the risk from an event occurring requiring the inoperable UPS HVAC Train, and the remaining UPS Room EFCUs and A/C Train fans providing the required protection.

C.1

When one or more UPS and Distribution Rooms are not supported by either forced cooling or circulating air, one hour is allowed to restore support to the affected room(s). The one hour minimizes the time without required support while allowing quick repairs or restoration of equipment.

D.1, D.2 and D.3

In MODE 1, 2, 3, or 4, if the required support to meet the LCO or to meet Required Actions in Condition A or B cannot be restored within the required Completion Time , the unit must be placed in a MODE that minimizes the risk. 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.20.1

Verifying each require EFCU operates for ≥ 1 continuous hour ensures that they are OPERABLE.

SR 3.7.20.2

Verifying each UPS A/C train operates for ≥ 1 hour ensures that they are OPERABLE and that all associated controls are functioning properly.

SR 3.7.20.3

This SR verifies that the each UPS A/C train starts and operates on an actual or simulated Safety Injection actuation signal and on an actual or simulated Blackout actuation signal. The 18 month frequency is consistent with the typical refueling cycle. 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.

REFERENCES

1. FSAR, Section 9.4C.8.

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 source, and alternate), and the onsite standby emergency power sources (Train A and Train B diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The 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 offsite power sources and a dedicated DG.

Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power, through step down startup transformers, to the 6.9 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the FSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network buses at plant switchyards to the onsite Class 1E ESF buses.

Certain required unit loads are started and/or returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 2 minutes after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service when the bus is energized or by the load sequencer.

The onsite standby power source for each 6.9 kV ESF bus is a dedicated DG. DGs 1EG1, 1EG2, 2EG1 and 2EG2 are dedicated to ESF buses 1EA1, 1EA2, 2EA1 and 2EA2 respectively. The DG starts automatically on a safety injection (SI) signal.

If the Diesel Generator voltage exceeds the minimum or maximum voltage limits for steady state operation, except for allowed transients (less than 3

(continued)

BASES

BACKGROUND (continued)

seconds), the Digital Voltage Regulator will be isolated automatically and excitation will be controlled by the “magnetics.” “Magnetics” will maintain the DG output voltage within the required TS limits. However, the passive voltage control provided by the “magnetics” will not allow adjustment of DG voltage, and the capability to synchronize the Diesel Generator with offsite power, to restore the offsite power to the safety bus, will not exist. The Digital Voltage Regulator can be repaired during DG operation, e.g., while the DG carries the safety bus loads, to restore the DG operability.

On an ESF bus undervoltage signal, the DG start signal is delayed 1 second to allow alternate source breaker closure. If the alternate source is not available the ESF bus undervoltage signal automatically starts the DG, (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). As a result of degraded voltage the preferred source is tripped after a time delay to assure that the bus loads exposure to degraded voltage, in the absence of a Safety Injection Actuation Signal (SIAS) is limited to 60 seconds. In the event of a SIAS, after the confirmation of degraded condition that it is not due to a motor start, the preferred source breaker is tripped instantly. Subsequently, if the alternate source does not alleviate the degraded condition, the alternate source is tripped after a time delay of 1.9 seconds. After the offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage and the DG has started, it will automatically tie to its respective bus, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls 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 ESF electrical loads are automatically connected to the available alternate power source. If the alternate source is not available, then the ESF electrical loads are connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are started and/or returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 2 minutes after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service when the bus is energized or by the load sequencer.

(continued)

BASES

BACKGROUND (continued)

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9; Ref. (3) and IEEE 387 (Ref. 13). The continuous service rating of each DG is 7000 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 6.9 kV ESF buses are listed in Reference 2. The maximum calculated load is less than 6300 kW. This maximum continuous service load is reflected in selected surveillances.

APPLICABLE SAFETY ANALYSES

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

The OPERABILITY of the AC electrical power sources 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 AC sources or one of the offsite AC sources OPERABLE during Accident conditions in the event of:

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

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network buses at the plant switchyards and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit. In addition, one automatic load sequencer per train must be OPERABLE.

(continued)

BASES

LCO (continued)

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

Offsite circuit #1 is fed from the 138 kV switchyard and offsite circuit # 2 is fed from the 345 kV switchyard. Circuit #1 is the preferred source for Unit 2 and alternate source for Unit 1. Circuit # 2 is the preferred source for Unit 1 and alternate source for Unit 2. Each offsite circuit can supply 6.9 kV Train A and Train B ESF busses for both Unit 1 and Unit 2.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on receipt of bus undervoltage signal. This will be accomplished within 10 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 ESF 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 with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to ready-to-load status on an SI signal while operating in parallel test mode.

The Diesel Generator, when operating on magnetics only, is considered not operable because the passive voltage control provided by the “magnetics” will not allow adjustment of DG voltage, and the capability to synchronize the Diesel Generator with offsite power, to restore the offsite power to the safety bus, will not exist.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The offsite AC sources must be separate and independent (to the extent possible). For the onsite DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESF bus, is required to have an operable transfer mechanism to that bus to support operability of that circuit.

Each circuit of offsite source can feed both trains. Preferred source breakers are normally closed and alternate source breakers are normally open. Each bus has automatic capability to transfer to the alternate source on loss of preferred source.

(continued)

BASES

LCO (continued)

LCO 3.8.1 is modified by a Note stating that one DG may be synchronized with the offsite power source under administrative controls for the purpose of surveillance testing. During such testing, only one of the redundant DGs shall be paralleled at any one time, leaving the other DG available in standby service.

Administrative controls for performing surveillance testing with the DG connected to an offsite circuit ensure or require that:

a. Weather conditions are conductive for performing the SR.

b. The offsite power supply and switchyard conditions are conductive for performing the SR, which includes ensuring that switchyard access is restricted and that no potential impactive activity within the switchyard is performed.

c. No equipment or systems assumed to be available for supporting the performance of the SR are removed from service.

d. Associated risks shall be managed in accordance with the TS 5.5.18, “Configuration Risk Management Program.”

e. All 6.9 kV safeguards buses (both units) are fed from their respective preferred offsite source.

f. 6.9 kV bus voltage for the unit requiring the DG test is $\geq$ 6750 V.

g. Terminate the test if the Reactor trips.

h. Terminate the test if system frequency, bus voltage, or DG load indicate a potential for a degrading grid. Specifically:

    1. Terminate the test if the DG steady state load $\geq$ 7000 kW or a greater limit established for the test.

    2. Terminate the test if the DG requires frequent or continuous adjustment to decrease its load in order to maintain the specified load for the DG test.

    3. Terminate the test if DG kVAR exceed 5000 kVAR.

    4. Terminate the test if bus steady state voltage decreases $\geq$ 200 V from the voltage at the start of the test.

(continued)

BASES

LCO (continued)

5. Terminate the test if bus steady state frequency is $\leq$ 59 Hz.

The Note is consistent with the NRC position provided in Information Notice 84-29, which “prohibits the use of DGs for purposes other than supplying standby power, when needed, and permits interconnection of the onsite and offsite sources only for short periods of time for the purpose of DG load retesting.” Thus, the DG under test need not be considered inoperable strictly due to being paralleled with offsite power during performance of the required testing.

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA. The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

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

(continued)

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated 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. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the steam driven (turbine driven) auxiliary feedwater pump, are not included.

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

a. The train has no offsite power supplying it 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) with a train with no offsite power available, and 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 Train A and Train B 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.

(continued)

BASES

ACTIONS (continued)

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.1

To ensure a highly reliable power source remains with an inoperable 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.

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. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included. 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 (Train A or Train B) is inoperable.

(continued)

BASES

ACTIONS

B.2 (continued)

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

Discovering one 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.

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 the OPERABLE DG. 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 applicable plant procedures will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

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

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

During performance of surveillance activities as a requirement for ACTION statements, the air-roll test shall not be performed.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

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 Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included.

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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

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.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition 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. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

Condition D is entered with no AC source to any train, (for CPSES this requires both offsite sources and DG inoperable) 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 inoperable. LCO 3.8.9 provides the appropriate restrictions for a inoperable train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

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 ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1

The SI sequencer(s) is an essential support system to both the offsite circuit

(continued)

BASES

ACTIONS

F.1 (continued)

and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the train. The 24 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

This Required Action is modified by a note. The note allows one sequencer channel to be bypassed for surveillance testing provided the other channel is operable. The 4 hours allows sufficient time to perform the required testing. Based on the low probability of an event requiring the sequencer in combination with a failure to the operable sequencer channel during the 4 hours, this period of inoperability for testing is acceptable.

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

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

I.1

A Blackout sequencer is an essential support system to the DG associated with a given ESF bus. The sequencer is required to provide the system response to a loss of or degraded ESF bus voltage signal. Therefore, the loss of the Blackout sequencer causes the associated DG to become inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

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

Where the SR discussed herein specify voltage and frequency tolerances, the following is applicable.

The minimum steady state output voltage of 6480 V allows for voltage drops to motors and other equipment down to the 120 V level to ensure that the loads will not experience voltage less than the minimum rated voltage. The maximum steady state output voltage of 7150 V ensures that, under lightly loaded conditions, motors and other equipment down to the 120 V level will not experience voltages more than the maximum rated voltage. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

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

SR 3.8.1.2 and SR 3.8.1.7

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SR are modified by a Note (Note 2 for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period. In addition, for SR 3.8.1.2, following prelube, a warmup period is allowed prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. For SR 3.8.1.2 and SR 3.8.1.7 testing, the diesel should be started from ambient conditions which means the diesel engine is cold or at a temperature consistent with manufacturer's recommendations.

The DG shall start using one of the following signals: 1) Manual, 2) Simulated or actual safeguards bus undervoltage, 3) Safety Injection simulated or actual signal in conjunction with a simulated or actual loss of offsite power signal, or 4) a Safety Injection simulated or actual signal by itself.

For SR 3.8.1.2, in order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions, accelerates to 441 RPM, and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The 31 day Frequency for SR 3.8.1.2, is consistent with Regulatory Guide 1.9 (Ref. 3) and Generic Letter 94-01 (Ref. 14). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

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

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3) and Generic Letter 94-01 (Ref. 14).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one 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 day tank is at or above the required level. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10% (562 gallons) plus 878 gallons which is credited in TS 3.8.3 in meeting the 7 day fuel oil storage requirement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

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

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is 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 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 preventative 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, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The frequency of 92 days is adequate to verify proper automatic operation of the fuel transfer pumps to maintain the required volume of fuel oil in the day tanks. This frequency corresponds to the testing requirements for pumps as contained in the ASME Code (Ref. 11).

SR 3.8.1.7

See SR 3.8.1.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Transfer of each 6.9 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 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 the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The single largest motor load on the bus at any given time is the Component Cooling Water pump load which has a name plate rating of 783 KW. This Surveillance may be accomplished by:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by IEEE-308 (Ref. 12), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b is a steady state voltage value to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).

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 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 OPERABIITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

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

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

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref.3), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all safety functions encountered from the loss of offsite power, including shedding of the nonessential loads, energization of the emergency buses in ≤ 10 seconds after auto-start signal, and energization of the respective loads from the DG. It further demonstrates the capability of the DG to automatically maintain the required steady state voltage and frequency.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

residual heat removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 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 operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts, achieves and maintains the required voltage and frequency within the specified time (10 seconds) from the safety injection signal and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 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 Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a DG emergency start which occurs from either a loss of voltage or an SI actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref.3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to approximately 110% of the continuous duty rating and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG. For the purposes of the 2 hour run, the minimum load is approximately 110% of the 6300 kW maximum design load in lieu of the 7000 kW continuous rating. The DG start for this Surveillance can be performed either from ambient or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

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

This Surveillance is modified by a Note 1 which states that momentary transients due to changing bus loads do not invalidate this test.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref.3).

The generator voltage shall be between 6480 V and 7150 V and frequency shall be 60± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

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

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are consistent with IEEE-308 (Ref. 13).

The intent of the requirement to automatically energize the emergency loads with offsite power is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref.3), 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 that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 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 operated independently for the partial Surveillance; as well

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

SR 3.8.1.18

Under accident and loss of offsite power conditions loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2), 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 that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 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 operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

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

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

The Frequency of 18 months takes into consideration 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 two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 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 operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed (441 rpm) within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start.

SR 3.8.1.21 and SR 3.8.1.22

These SRs ensure the proper functioning of the safety injection and blackout sequencers.

SR 3.8.1.21 applies to the blackout sequencer input undervoltage relays. These relays are calibrated every 18 months.

SR 3.8.1.22 applies to the Solid State Safeguards Sequencers (both the Safety Injection Sequencer and the Blackout Sequencer) and is the performance of a TADOT. This surveillance is performed every 31 days.

This SR is modified by two Notes. The first Note excludes verification of setpoints from the TADOT. The trip setpoints are verified by as part of the ESF Instrumentation. The second Note excludes actuation of final devices. Operation of the sequencer during power operations could disrupt normal operation and induce a plant transient.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9 Rev 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, January 1978.
11. ASME Code for Operation and Maintenance of Nuclear Power Plants.
12. IEEE Standard 308-1974.
13. IEEE Standard 387-1977
14. Generic Letter 94-01, “Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators,” May 31, 1994.
15. ANSI C84.1

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

In addition to the requirements established by the technical specifications, the plant staff must also manage shutdown tasks and electrical support to maintain risk at an acceptably low value.

As required by the technical specifications, one train of the required equipment during shutdown conditions is supported by one train of AC and DC power and distribution. The availability of additional equipment, both redundant equipment as required by the technical specifications and equipment not required by the specifications, contributes to risk reduction and this equipment should be supported by reliable electrical power systems. Typically the Class 1E power sources and distribution systems of the unit are used to power this equipment because these power and distribution systems are available and reliable. When portions of the Class 1E power or distribution systems are not available (usually as a result of maintenance or modifications), other reliable power sources or distribution are used to provide the needed electrical support. The plant staff assesses these alternate power sources and distribution systems to assure that the desired level of minimal risk is maintained (frequently referred to as maintaining a desired defense in depth). The level of detail involved in the assessment will vary with the significance of the equipment being supported. In some cases, prepared guidelines are used which include controls designed to manage risk and retain the desired defense in depth.

The AC sources satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

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 the 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 postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus. Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

Offsite circuit #1 is fed from the 138 kv switchyard and offsite circuit # 2 is fed from the 345 kv switchyard. Circuit #1 is the preferred source for Unit 2 and alternate source for Unit 1. Circuit # 2 is the preferred source for Unit 1 and alternate source for Unit 2. Each offsite circuit can supply 6.9 kv Train A and Train B ESF busses for both Unit 1 and Unit 2.

The DG must be capable of starting, accelerating to rated speed (441 RPM) and voltage, and connecting to its respective ESF bus on receipt of a bus undervoltage signal. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting the required loads manually, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions.

The DG must be supporting the train of AC electrical distribution required to be OPERABLE per LCO 3.8.10. The offsite circuit must also support the train of AC electrical distribution required to be OPERABLE per LCO 3.8.10. When the second AC electrical power distribution train (subsystem) is needed to support redundant required systems, equipment and components, the second train may be energized from any available source. The available source must be Class 1E or another reliable source. The available source must be capable of supplying sufficient AC electrical power such that the redundant components are capable of performing their specified safety function(s) (implicitly required by the definition of OPERABILITY). Otherwise, the supported components must be declared inoperable and the appropriate conditions of the LCOs for the redundant components must be entered.

(continued)

BASES

LCO (continued)

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to one required ESF train. The one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required 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, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

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 may allow dilution of the RCS but the source of makeup water is required to contain sufficient boron concentration such that when mixed with the RCS inventory the resulting boron concentration in the RCS meets the 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 or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be 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 the required ESF 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 would provide 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 SR 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. Table B 3.8.2-1 discusses the applicability of the 3.8.1 surveillances.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SR, and to preclude deenergizing a required 6.9 KV ESF bus or disconnecting a required offsite circuit during performance of SR. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SR must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES None.

Table B 3.8.2-1 (page 1 of 1)
Scope of SR 3.8.2.1

SR	APPLICABLE	PERFORM	COMMENT
3.8.1.1	Yes	Yes	
3.8.1.2	Yes	Yes	
3.8.1.3	Yes	No	Requires DG in synch with grid
3.8.1.4	Yes	Yes	
3.8.1.5	Yes	Yes	
3.8.1.6	Yes	Yes	
3.8.1.7	Yes	Yes	
3.8.1.8	No	No	Requires two offsite sources
3.8.1.9	Yes	No	Load reject test puts DG at risk
3.8.1.10	Yes	No	Load reject test puts DG at risk
3.8.1.11 (except c.2)	Yes	No	Do not want to load shed OPERABLE bus.
3.8.1.11 c.2	No	No	Requires OPERABLE sequencer
3.8.1.12	No	No	Requires SI signal
3.8.1.13	No	No	Requires SI signal
3.8.1.14	Yes	No	Requires operation of OPERABLE DG with grid
3.8.1.15	Yes	No	Requires operation of OPERABLE DG with grid
3.8.1.16	Yes	No	Requires operation of OPERABLE DG with grid
3.8.1.17	No	No	Requires SI signal
3.8.1.18	No	No	Requires OPERABLE sequencer
3.8.1.19	No	No	Requires SI signal
3.8.1.20	No	No	Requires two OPERABLE DGs
3.8.1.21	No	No	Requires OPERABLE sequencer
3.8.1.22	No	No	Requires OPERABLE sequencer

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that diesel for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand discussed in the FSAR, Section 9.5.4.1 (Ref. 1). The maximum load demand is calculated using the assumption that a minimum of any two DGs is available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from storage tank to day tank by either of two transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SR are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of 7 days of operation based on conservative lube oil consumption rate.

Each DG has an air start system which is sized with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 4), and in the FSAR, Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for one DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem supports LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated 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.

(continued)

BASES

ACTIONS (continued)

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period. The amount of fuel oil required during Modes 5 & 6 is less because fewer loads are required to maintain the plant during shutdown conditions.

B.1

With lube oil inventory less than a level 1.75 inches below the static low level mark on the lube oil dipstick, sufficient lubricating oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain greater than a level 5.5 inches below the static low level mark on the lube oil dipstick. This level ensures that if the engine starts, the run level is above where vortexing occurs and at least 48 hours of run time is available before lube oil addition is required. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity, the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently

(continued)

BASES

ACTIONS

C.1 (continued)

demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, 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.

E.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil, lube oil, or 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 to support each DG's operation for approximately 7 days at full load. A small volume in the day tank in excess of the day tank requirements is credited to ensure a full 7 day supply. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

SR 3.8.3.2

The surveillance contains a note that states that it is required only when the engine has been in shutdown for > 10 hours. This allowance is required

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

because the lube oil level drops when the engine is running and does not immediately return to static conditions.

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG based on an engine lube oil consumption rate of 1.5 gallon per hour. The 1.75" below the low static level requirement is based on conservative DG consumption values. Implicit in this SR is the requirement to verify adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the unit staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion, and when added to the tank existing volume will maintain the tank volume absolute specific gravity range of $\geq$ 0.8348 and $\leq$ 0.8927 at 60/60^{o}F or an API gravity range of $\geq$ 27^{o} and $\leq$ 38^{o} at 60^{o}F. 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. Tests a through d are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests a through d to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-1981 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-1981 (Ref. 6) that the sample has an absolute specific gravity at 60/60^{o}F of $\geq$ 0.8156 and $\leq$ 0.8927 or an API gravity at 60^{o}F of $\geq$ 27^{o} and $\leq$ 42^{o} when tested in accordance with ASTM D1298-1980 (Ref. 6), a kinematic viscosity at 40^{o}C of $\geq$ 1.9 centistokes and $\leq$ 4.1 centistokes, and a flash point of $\geq$ 125^{o}F,

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-1982 or a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

d. water and sediment content within limits when tested in accordance with ASTM D1796-1968 (Ref. 6),

e. Verify by analysis that after the new fuel is added to the tank(s), the tank(s) will have an absolute specific gravity at 60/60°F of $\geq$ 0.8348 and $\leq$ 0.8927 or an API gravity at 60°F of $\geq$ 27° and $\leq$ 38°, and

f. Within 31 days after addition to the tank(s), verify by sampling the appropriate storage tank(s) that the fuel in the tank(s) has an absolute specific gravity at 60/60°F of $\geq$ 0.8348 and $\leq$ 0.8927 or an API gravity at 60°F of $\geq$ 27° and $\leq$ 38°.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-1981 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-1981 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-1979, ASTM D2622-1982, or ASTM D4294-2003 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on 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 D2276-1978, Method A, or D5452-2000 (Ref. 6). 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. For those designs in which the total stored fuel oil volume is contained in two or more interconnected tanks, each tank must be considered and tested separately.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4 (continued)

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The receiver design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which one start 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.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and 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. FSAR, Section 9.5.4.1.
2. Regulatory Guide 1.137.
3. ANSI N195-1976, Appendix B.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.

(continued)

BASES

REFERENCES (continued)

6. ASTM Standards: D4057-1981; D975-1981; D1298-1980; D4176-1982; D1796-1968; D1552-1979; D2622-1982; D4294-2003; D2276-1978, Method A, D5452-2000.

7. ASTM Standards, D975-1981, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station DC electrical power system provides control power to selected equipment. It also provides both motive and control power to selected safety related equipment and preferred AC vital bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Train A and Train B). Each subsystem consists of two 125 VDC batteries, the associated battery chargers for each battery, and all the associated control equipment and interconnecting cabling.

There are two 100% capacity battery chargers per battery. One charger for each battery is required operating and the other is kept as a spare (refer to Table B 3.8.4-1, DC Sources). If the spare battery charger is substituted, then the requirements of independence and redundancy between subsystems are maintained.

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

The Train A and Train B DC electrical power subsystems provide the control power for its associated Class 1E AC power loads fed from 6.9 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 AC vital buses.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

125 VDC batteries of each subsystem (train) are 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

(continued)

BASES

BACKGROUND (continued)

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.

Each battery has adequate capacity to meet the duty cycle(s) discussed in the FSAR, Chapter 8 (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train A and Train B DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life and the 100% design demand. The minimum design voltage limit is 105 V.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 2.065 volts per cell (Vpc). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with cell float voltage ≥ 2.07 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. The battery float charge voltage limit is established as 2.13 V per cell, which corresponds to a total minimum float voltage output of 128 V for a 60 cell battery. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.20 Vpc corresponds to a total float voltage output of 132 V for a 60 cell battery as discussed in the FSAR, Chapter 8 (Ref. 4).

Each Train A and Train B DC electrical power 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 also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in the FSAR, Chapter 8 (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The

(continued)

BASES

BACKGROUND (continued)

equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 5), and in the FSAR, Chapter 15 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The DC electrical power subsystems, each subsystem consisting of two batteries, a battery charger for each battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any one train of DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

(continued)

BASES

LCO (continued)

An OPERABLE DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es). (Reference Table B 3.8.4-1)

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

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

Condition A represents one train with one or two required battery chargers inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focus on returning the affected one or two batteries to the fully charged state and restoring a fully qualified charger for each battery to OPERABLE status in a reasonable time period. Required Action A.1 requires that the terminal voltage of the affected battery(ies) be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the required charger(s) to OPERABLE status or providing an alternate means of restoring the associated battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the terminal voltage of the affected battery(ies) to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the affected battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge

(continued)

BASES

ACTIONS

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

characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the affected battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps, then Condition D is entered as a result of the Required Action and Completion Time not met. At the same time, this indicates there may be additional battery problems. Without adequate assurance that the battery can be recharged within 12 hours, the affected battery must also be declared inoperable and LCO 3.8.4 Condition B entered for the inoperable battery, which is consistent with battery parameter requirements and actions of LCO 3.8.6 (Condition B and F).

Required Action A.3 limits the restoration time for the inoperable required battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day completion time reflects a reasonable time to effect restoration of the qualified battery charger to operable status.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B represents one train with one or two batteries inoperable. With one or two batteries inoperable, the affected DC bus(es) are being supplied by their associated OPERABLE battery charger(s). Any event that results in a loss of the AC bus supporting the battery charger(s) will also result in loss of or degraded DC to that train. Recovery of the AC bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon DC power being supplied from the batteries. In addition, the energization transients of any DC loads that are beyond the capability of the associated battery charger(s) and normally require the assistance of the batteries will not be able to be brought online. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

C.1

Condition C represents one train with a loss of ability to respond to an event, and a loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power subsystems is inoperable, the other DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of the minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function 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.

(continued)

BASES

ACTIONS (continued)

D.1 and D.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 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger supplies a continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer. The minimum established float voltage is 2.13 Vpc or 128 V at the battery terminals. This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 300 amps at the minimum established charger test voltage of 130 volts or greater for 8 hours. The ampere requirements are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.3

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in FSAR Chapter 8 (Ref. 4).

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests, not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. This note does not prohibit the application of LCO 3.0.5 or the performance of this SR to restore equipment operability. Note 2 neither approves nor prohibits testing in MODES 1 and 2; however, for testing that is performed in MODES 1 and 2 (e.g., for post work testing) the testing may not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

be credited to satisfy the SR. Only the testing performed in MODES 3, 4, 5, 6 or with core off-loaded can be credited to satisfy the SR.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1974.
4. FSAR, Chapter 8.
5. FSAR, Chapter 6.
6. FSAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974.
8. IEEE-450-1995.
9. Regulatory Guide 1.32, February 1977.
10. Regulatory Guide 1.129, February 1978.

Table B 3.8.4-1 (page 1 of 1)
DC Sources

TRAIN A		TRAIN B	
125 V DC Bus 1ED1(2ED1) Energized From Battery BT1ED1(BT2ED1) and Battery Charger BC1ED1-1 (BC2ED1-1) or BC1ED1-2 (BC2ED1-2)	125 V DC Bus 1ED3(2ED3) Energized From Battery BT1ED3(BT2ED3) and Battery Charger BC1ED3-1 (BC2ED3-1) or BC1ED3-2 (BC2ED3-2)	125 V DC Bus 1ED2(2ED2) Energized From Battery BT1ED2(BT2ED2) and Battery Charger BC1ED2-1 (BC2ED2-1) or BC1ED2-2 (BC2ED2-2)	125 V DC Bus 1ED4(2ED4) Energized From Battery BT1ED4(BT2ED4) and Battery Charger BC1ED4-1 (BC2ED4-1) or BC1ED4-2 (BC2ED4-2)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, 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 the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In addition to the requirements established by the technical specifications, the plant staff must also manage shutdown tasks and electrical support to maintain risk at an acceptably low value.

As required by the technical specifications, one train of the required equipment during shutdown conditions is supported by one train of AC and DC power and distribution. The availability of additional equipment, both redundant equipment as required by the technical specifications and equipment not required by the specifications, contributes to risk reduction and this equipment should be supported by reliable electrical power systems. Typically the Class 1E power sources and distribution systems of the unit are used to power this equipment because these power and distribution systems are available and reliable. When portions of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Class 1E power or distribution systems are not available (usually as a result of maintenance or modifications), other reliable power sources or distribution are used to provide the needed electrical support. The plant staff assesses these alternate power sources and distribution systems to assure that the desired level of minimal risk is maintained (frequently referred to as maintaining a desired defense in depth). The level of detail involved in the assessment will vary with the significance of the equipment being supported. In some cases, prepared guidelines are used which include controls designed to manage risk and retain the desired defense in depth.

The DC sources satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

One DC electrical power subsystem consisting of two batteries, at least one full capacity battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support one train of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The required DC electrical power distribution subsystem is supported by one train of DC electrical power system. When the second DC electrical power distribution train (subsystem) is needed to support redundant required systems, equipment and components, the second Train may be energized from any available source. The available source must be Class 1E or another reliable source. The available source must be capable of supplying sufficient DC electrical power such that the redundant components are capable of performing their specified safety function(s) (implicitly required by the definition of OPERABILITY). Otherwise, the supported components must be declared inoperable and the appropriate conditions of the LCOs for the redundant components must be entered.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

(continued)

BASES

APPLICABILITY (continued)

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

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

By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO 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 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 may allow dilution of the RCS but the source of makeup water is required to contain sufficient boron concentration such that when mixed with the RCS inventory the resulting boron concentration in the RCS meets the 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 postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for

(continued)

BASES

ACTIONS	A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued) actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.
SURVEILLANCE REQUIREMENTS	SR 3.8.5.1 SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR. This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SR 3.8.4.2 and SR 3.8.4.3. It is the intent that these SRs must still be capable of being met, but actual performance is not required.
REFERENCES	1. FSAR, Chapter 6. 2. FSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC power subsystem batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources -Operating," and LCO 3.8.5, "DC Sources -Shutdown." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.19 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications" (Ref.4).

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 2.065 volts per cell (Vpc). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with cell float voltage x 2.07 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.20 Vpc corresponds to a total float voltage output of 132 V for a 60 cell battery as discussed in the FSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, 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, in the event of:

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

b. A worst case single failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Battery parameters satisfy the Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the CPSES Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.19.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one or more batteries in one train < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify “perform,” a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Conditions(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed when in Condition A, then there is not assurance that there is still sufficient battery capacity to perform the intended function. In this case the battery must be declared inoperable and Condition F must be entered.

B.1 and B.2

One or more batteries in one train with float current > 2 amps indicates that a

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addressed charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V and float current greater than 2 amps, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not an indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

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BASES

ACTIONS (continued)

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

With one or more batteries in one train with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.19, Battery Monitoring and Maintenance Program). They are modified by a note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. Required Action C.2 for visual inspection of the battery to verify no leakage, and the parallel program requirement of 5.5.19.b to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the batteries may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries in one train with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With one or more batteries in redundant trains with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer completion times

(continued)

BASES

ACTIONS

E.1 (continued)

specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one train within 2 hours.

F.1

With one or more batteries with any battery parameter, outside the allowances of the Required Actions for Condition A, B, C, D, or E sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC battery must be declared inoperable. Additionally, discovering one or more batteries in one train with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 4). The 7 day Frequency is consistent with IEEE-450 (Ref. 4).

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 132 V for 60 cells at the battery terminals, or 2.20 Vpc. This provides adequate over-

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.2 and SR 3.8.6.5 (continued)

potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. The minimum float voltage required by the battery manufacturer is 2.13 Vpc which corresponds to 128 V for 60 cells at the battery terminals. Float voltages in the range of less than 2.13 Vpc, but greater than 2.07 Vpc, are addressed in Specification 5.5.19. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450 (Ref. 4).

SR 3.8.6.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 4).

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 70ºF). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 4).

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load. This will confirm the battery's ability to meet the critical period of the load duty cycle, in addition to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

determining its percentage of rated capacity. Initial conditions for the modified performance discharge test will be identical to those specified for a service test and the test discharge rate will envelope the duty cycle of the service test if the modified performance discharge test is performed in lieu of a service test.

It may consist of just two rates; for instance 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 must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 4) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 18 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 rating. Degradation is indicated, according to IEEE-450 (Ref. 4), when the battery capacity drops by more than 10% from its capacity of the previous performance test, or is below 90% of the manufacturer's rating. This frequency is consistent with the recommendations in IEEE-450 (Ref. 4).

This SR is modified by a Note. This Note says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. This note does not prohibit the application of LCO 3.0.5 or the performance of this SR to restore equipment operability. The Note neither approves nor prohibits testing in MODES 1 and 2; however, for testing that is performed in MODES 1 and 2 (e.g., for post work testing) the testing may not be credited to satisfy the SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

Only the testing performed in MODES 3, 4, 5, 6 or with core off-loaded can be credited to satisfy the SR.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 8.
3. FSAR, Chapter 15.
4. IEEE-450-1995.
5. IEEE-485-1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital buses. The inverters are powered from the 125 V DC system. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the FSAR, Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required AC vital buses OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

(continued)

BASES

LCO (continued)

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The eight inverters (four per train) ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV safety buses are de-energized. There is also an “installed spare” inverter for each train. The spare inverter may be manually aligned to substitute for any of the four inverters in that train.

Operable inverters require the associated vital bus to be powered by the inverter with output voltage within tolerances, and power input to the inverter from a 125 VDC system. (Ref. Table B 3.8.7-1).

This LCO is modified by a Note that allows two inverters, associated with a battery, to be disconnected from the battery for 24 hours, if the vital bus(es) are powered from a Class 1E transformer during the period and all other inverters are operable. This allows an equalizing charge to be placed on the battery. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while taking into consideration the time required to perform an equalizing charge on the battery bank.

The intent of this Note is to limit the number of inverters that may be disconnected. Only those inverters associated with the single battery undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries, regardless of the number of inverters or unit design.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is re-energized by an operable inverter or the alternate bypass power supply from the Class 1E transformers.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from its Class 1E transformer, it is relying upon non-regulating interruptible AC electrical power sources (offsite and onsite). Because of the potential impact of interrupted power on the Emergency Diesel Generator and the Solid State Safeguards Blackout Sequencer during a postulated Loss of Offsite Power event, these components are considered inoperable when operating on inverter bypass power, and evaluated under the SFDP of Specification 5.5.15. The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. The 7 day Frequency takes into account the

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.8.7.1 (continued) redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.
REFERENCES	1. FSAR, Chapter 8. 2. FSAR, Chapter 6. 3. FSAR, Chapter 15.

Table B 3.8.7-1 (page 1 of 1)
Inverters

TRAIN A*		TRAIN B*	
118 V AC Vital Bus 1PC1(2PC1) Energized From Inverter IV1PC1(IV2PC1) or IV1EC1/3(IV2EC1/3)[1] connected to 125 V DC Bus 1ED1(2ED1)	118 V AC Vital Bus 1PC3(2PC3) Energized From Inverter IV1PC3(IV2PC3) or IV1EC1/3(IV2EC1/3)[1] connected to 125 V DC Bus 1ED3(2ED3)	118 V AC Vital Bus 1PC2(2PC2) Energized From Inverter IV1PC2(IV2PC2) or IV1EC2/4(IV2EC2/4)[2] connected to 125 V DC Bus 1ED2(2ED2)	118 V AC Vital Bus 1PC4(2PC4) Energized From Inverter IV1PC4(IV2PC4) or IV1EC2/4(IV2EC2/4)[2] connected to 125 V DC Bus 1ED4(2ED4)
118 V AC Vital Bus 1EC1(2EC1) Energized From Inverter IV1EC1(IV2EC1) or IV1EC1/3(IV2EC1/3)[1] connected to 125 V DC Bus 1ED1(2ED1)	118 V AC Vital Bus 1EC5(2EC5) Energized From Inverter IV1EC3(IV2EC3) or 1V1EC1/3(IV2EC1/3)[1] connected to 125 V DC Bus 1ED3(2ED3)	118 V AC Vital Bus 1EC2(2EC2) Energized From Inverter IV1EC2(IV2EC2) or IV1EC2/4(IV2EC2/4)[2] connected to 125 V DC Bus 1ED2(2ED2)	118 V AC Vital Bus 1EC6(2EC6) Energized From Inverter IV1EC4(IV2EC4) or IV1EC2/4(IV2EC2/4)[2] connected to 125 V DC Bus 1ED4(2ED4)

* A spare inverter is provided for each train. The spare inverter may be manually aligned to substitute for any one of the four inverters in its train.

1. IV1EC1/3(IV2EC1/3) is the installed spare inverter for Train A.

2. IV1EC2/4(IV2EC2/4) is the installed spare inverter for Train B.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each AC vital bus during MODES 5 and 6 ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

In addition to the requirements established by the technical specifications, the plant staff must also manage shutdown tasks and electrical support to maintain risk at an acceptably low value.

As required by the technical specifications, one train of the required equipment during shutdown conditions is supported by one train of AC and DC power and distribution. The availability of additional equipment, both redundant equipment as required by the technical specifications and equipment not required by the specifications, contributes to risk reduction and this equipment should be supported by reliable electrical power systems. Typically the Class 1E power sources and distribution systems of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the unit are used to power this equipment because these power and distribution systems are available and reliable. When portions of the Class 1E power or distribution systems are not available (usually as a result of maintenance or modifications), other reliable power sources or distribution are used to provide the needed electrical support. The plant staff assesses these alternate power sources and distribution systems to assure that the desired level of minimal risk is maintained (frequently referred to as maintaining a desired defense in depth). The level of detail involved in the assessment will vary with the significance of the equipment being supported. In some cases, prepared guidelines are used which include controls designed to manage risk and retain the desired defense in depth.

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

One train of inverters needed to power two 118 volt AC instrument busses (channel-oriented) and two 118 volt AC instrument busses (non-channel oriented) shall be connected to their respective DC busses and shall be OPERABLE to support one train of the distribution systems required to be OPERABLE by LCO 3.8.10. The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The battery powered inverters provide uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV safety buses are de-energized. OPERABILITY of the inverters requires that the AC vital bus be powered by the inverter. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The required AC vital bus electrical power distribution subsystem is supported by one train of inverters. When the second (subsystem) of AC vital bus electrical power distribution is needed to support redundant required systems, equipment and components, the second train may be energized from any available source. The available source must be Class 1E or another reliable source. The available source must be capable of supplying sufficient AC electrical power such that the redundant components are capable of performing their specified safety function(s) (implicitly required by the definition of OPERABILITY). Otherwise, the supported components must be declared inoperable and the appropriate conditions of the LCOs for the redundant components must be entered.

(continued)

BASES (continued)

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

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

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 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 may allow dilution of the RCS but the source of makeup water is required to contain sufficient boron concentration such that when mixed with the RCS inventory the resulting boron concentration in the RCS meets the 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 postulated events. It is further required to

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and AC vital bus electrical power distribution subsystems.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 6.9 kV bus and secondary load centers and 480 and 120 V buses. Each 6.9 kV ESF bus has two separate and independent offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 6.9 kV ESF bus is normally connected to a preferred offsite source. After a loss of the preferred offsite power source to a 6.9 kV ESF bus, a slow transfer to the alternate offsite source is accomplished. If the alternate offsite sources are unavailable, the onsite emergency DG supplies power to the 6.9 kV ESF bus. Control power for the 6.9 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

The secondary AC electrical power distribution system for each train includes the safety related load centers shown in Table B 3.8.9-1.

The 118 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E transformers powered from the same train as the associated inverter, 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 FSAR, Chapter 6 (Ref. 1), and in the FSAR, Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems. The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF 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, and load 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 vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via inverted DC voltage or the alternate bypass power supply via Class 1E transformers.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

(continued)

BASES

APPLICABILITY (continued)

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and Adequate core cooling is provided, and containment

b. 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 buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated 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.

(continued)

BASES

ACTIONS (continued)

B.1

With one AC vital bus inoperable the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, or alternate bypass power via Class 1E transformers.

Condition B represents one AC vital bus without non-interruptible inverted DC power. In this situation, the unit is significantly more vulnerable to a complete loss of all non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of non-interruptible power to the remaining vital buses and restoring power to the affected vital bus subsystems.

This 2 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 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one or more electrical power distribution subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning for the affected bus(es). 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 bus(es) and restoring power to the affected bus(es).

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while 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 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 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

(continued)

BASES

ACTIONS (continued)

D.1 and D.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 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN A*#	TRAIN B*#
AC safety buses	6900 V 480 V	ESF Bus 1EA1 (2EA1) Load Centers 1EB1, 1EB3 (2EB1, 2EB3)	ESF Bus 1EA2 (2EA2) Load Centers 1EB2, 1EB4 (2EB2, 2EB4)
DC buses	125 V	Bus 1ED1 (2ED1) Bus 1ED3 (2ED3)	Bus 1ED2 (2ED2) Bus 1ED4 (2ED4)
AC vital buses	118 V	Buses 1EC1, 1EC5 (2EC1, 2EC5) Buses 1PC1, 1PC3 (2PC1, 2PC3)	Buses 1EC2, 1EC6 (2EC2, 2EC6) Buses 1PC2, 1PC4 (2PC2, 2PC4)

* Each train of the AC and DC electrical power distribution systems is a subsystem.

#The 480 V load centers are fed from the following transformers:

1EB1 - T1EB1
1EB2 - T1EB2
1EB3 - T1EB3
1EB4 - T1EB4
2EB1 - T2EB1
2EB2 - T2EB2
2EB3 - T2EB3
2EB4 - T2EB4

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power distribution subsystems during MODES 5 and 6, ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In addition to the requirements established by the technical specifications, the plant staff must also manage shutdown tasks and electrical support to maintain risk at an acceptably low value.

As required by the technical specifications, one train of the required equipment during shutdown conditions is supported by one train of AC and DC power and distribution. The availability of additional equipment, both redundant equipment as required by the technical specifications and equipment not required by the specifications, contributes to risk reduction and this equipment should be supported by reliable electrical power systems. Typically the Class 1E power sources and distribution systems of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the unit are used to power this equipment because these power and distribution systems are available and reliable. When portions of the Class 1E power or distribution systems are not available (usually as a result of maintenance or modifications), other reliable power sources or distribution are used to provide the needed electrical support. The plant staff assesses these alternate power sources and distribution systems to assure that the desired level of minimal risk is maintained (frequently referred to as maintaining a desired defense in depth). The level of detail involved in the assessment will vary with the significance of the equipment being supported. In some cases, prepared guidelines are used which include controls designed to manage risk and retain the desired defense in depth.

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of one train of the electrical distribution system as necessary to support OPERABILITY of one train 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 energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The AC electrical power distribution subsystems are supported by one train of AC electrical power sources as required by LCO 3.8.2, “AC Sources - Shutdown.”

The required DC electrical power distribution subsystem is supported by one train of DC electrical power system as required by LCO 3.8.5, “DC Sources - Shutdown.” When the second DC electrical power distribution train (subsystem) is needed to support redundant required systems, equipment and components, the second Train may be energized from any available source. The available source must be Class 1E or another reliable source. The available source must be capable of supplying sufficient DC electrical power such that the redundant components are capable of performing their specified safety function(s) (implicitly required by the definition of

(continued)

BASES

LCO (continued)

OPERABILITY). Otherwise, the supported components must be declared inoperable and the appropriate conditions of the LCOs for the redundant components must be entered.

The required AC vital bus electrical power distribution subsystem is supported by one train of inverters as required LCO 3.8.8, “Inverters - Shutdown.” When the second (subsystem) of AC vital bus electrical power distribution is needed to support redundant required systems, equipment and components, the second train may be energized from any available source. The available source must be Class 1E or another reliable source. The available source must be capable of supplying sufficient AC electrical power such that the redundant components are capable of performing their specified safety function(s) (implicitly required by the definition of OPERABILITY). Otherwise, the supported components must be declared inoperable and the appropriate conditions of the LCOs for the redundant components must be entered.

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

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 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 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 postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem 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 and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR 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 AC, DC, and AC vital bus electrical power distribution subsystems are functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1 (continued)

control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity that have direct access to the reactor vessel during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the main system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain 0.95 during the refueling operation. Hence, at least a 5% k/k margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). Boron dilution accidents are precluded in MODE 6 by isolating potential dilution flow paths. See LCO 3.9.2, “Unborated Water Source Isolation Valves.”

The RCS boron concentration satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The LCO requires that a minimum uniform boron concentration be maintained in the filled portions of the RCS, the refueling canal, and the refueling cavity that have direct access to the reactor vessel while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations.

Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" LCO 3.1.5, “Shutdown Bank Insertion Limits,” and LCO, “Control Bank Insertion Limits,” ensure that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

The applicability is modified by a Note stating that transition from MODE 5 to MODE 6 is not permitted. This Note specifies an exception to LCO 3.0.4 and prohibits the transition when boron concentration limits are not met. This note assures that core reactivity is maintained within limits during fuel handling operations.

(continued)

BASES (continued)

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 any coolant volume in the filled portions of the RCS, the refueling canal or the refueling cavity, that have direct access to the reactor vessel is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g., temperature fluctuations, 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.

When determining compliance with actions, addition of borated water with a concentration greater than or equal to the minimum required RWST concentration shall not be considered a positive reactivity change (Ref.3).

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once 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 that the coolant boron concentration in the filled portions of the RCS, and all the filled portions of the refueling canal and the refueling cavity, that have direct access to the reactor vessel is within the COLR limits.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1 (continued)

The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. FSAR, Chapter 15.

3. NRC letter (W. Reckley to N. Carns) dated November 22, 1993: “Wolf Creek Generating Station - Positive Reactivity Addition; Technical Specification Bases Changes”

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Isolation Valves

BASES

BACKGROUND

During MODE 6 operations, all isolation valves for reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves (either CS-8455 or CS-8560, CS-8439, FCV-111B, CS-8441 and CS-8453) must be secured in the closed position.

The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by reducing the boron concentration is inappropriate during MODE 6, isolation of all unborated water sources prevents an unplanned boron dilution.

APPLICABLE SAFETY ANALYSES

The possibility of an inadvertent boron dilution event (Ref. 1) occurring during MODE 6 refueling operations is precluded by adherence to this LCO, which requires that potential dilution sources be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portion of the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required for MODE 6.

The RCS boron concentration satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

This LCO requires that flow paths to the RCS from unborated water sources be isolated to prevent unplanned boron dilution during MODE 6 and thus avoid a reduction in SDM.

APPLICABILITY

In MODE 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of all sources of unborated water to the RCS.

For all other MODES, the boron dilution accident was analyzed and was found to be capable of being mitigated.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately. The Completion Time of "immediately" for performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

Condition A has been modified by a Note to require that Required Action A.4 be completed whenever Condition A is entered.

A.3

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valves secured closed. Securing the valves in the closed position, under administrative controls, ensures that the valves are not inadvertently opened. The Completion Time of "immediately" requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

A.4

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution paths. Secured closed includes a mechanical stop for the manual isolation valve CS-8455 or mechanical stops for the manual isolation valves CS-8439, CS-8441, CS-8560, and CS-8453 and removal of air or electrical power from the fail-closed, air operated valve FCV-111B. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1 (continued)

that all unborated water sources are isolated, precluding a dilution. The boron concentration is checked every 72 hours during MODE 6 under SR 3.9.1.1. This Surveillance demonstrates that the valves are closed through a system walkdown (which may include the use of local or remote indicators). The 31 day Frequency is based on engineering judgment and is considered reasonable in view of other administrative controls that will ensure that the valve opening is an unlikely possibility.

REFERENCES

1. FSAR, Section 15.

2. NUREG-0800, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. These detectors are located external to the reactor vessel and detect neutrons leaking from the core. Either of two functionally-equivalent sets of neutron flux monitors may be used.

The installed Westinghouse BF_3 source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). The installed source range neutron flux monitors are BF_3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps). The detectors also provide continuous visual indication in the control room. The NIS is designed in accordance with the criteria presented in Reference 1. Each portion of the Westinghouse source range neutron flux monitors has two trains and each is assigned to an independent Class 1E electrical train. These trains are physically and electrically separated in accordance with applicable IEEE Standards.

A separate Gamma-Metrics Neutron Flux Monitoring System (NFMS) is installed to satisfy the requirements of Regulatory Guide 1.97, “Instrumentation For Light-Watered-Cooled Nuclear Power Plants To Assess Plant And Environs Conditions During And Following An Accident.” The Gamma-Metrics NFMS monitors neutron flux from the source range through 200% Rated Thermal Power (RTP) during all Modes of plant operation. This system utilizes two separate Safety Category I (Class 1E) fission chamber neutron detectors for all ranges of neutron flux indication. Each portion of the Gamma-Metrics instrumentation has two trains and each is assigned to a separate Class 1E electrical train. These trains are physically and electrically separated in accordance with applicable IEEE Standards.

The source range neutron flux monitors do not provide a Reactor Protection System function in Mode 6.

Because it is considered important to use detectors on opposing sides of the core to effectively monitor the core reactivity, the use of one BF_3 detector and one Gamma-Metrics detector is not permitted.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors from either set of source range neutron flux monitor systems are required to provide a visual

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly.

The source range neutron flux monitors satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each monitor must provide visual indication in the control room. Both monitors used to satisfy this LCO must be from the same set of available neutron flux monitoring systems.

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In other MODES, the source range monitors are governed by LCO 3.3.1, LCO 3.3.3, and LCO 3.3.4.

ACTIONS

A.1 and A.2

With only one required source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, 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. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position. Addition to the RCS of borated water with a concentration greater than or equal to the minimum required RWST concentration shall not be considered to be a positive reactivity change (Ref 3).

(continued)

BASES

ACTIONS (continued)

B.1

With no required source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no required source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and boron concentration changes inconsistent with Required Action A.2 are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.3.2

SR 3.9.3.2 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 neutron flux monitors includes obtaining

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.2 (continued)

the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.

2. FSAR, Section [15.2.4].

3. NRC letter (W. Reckley to N. Carns) dated November 22, 1993 “Wolf Creek Generating Station - Positive Reactivity Addition; Technical Specification Bases Changes”.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the 10CFR50, Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. If closed, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced. Alternatively, the equipment hatch can be open provided it can be installed with a minimum of four bolts holding it in place.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; however both personnel air lock doors may be open provided that one personnel air

(continued)

BASES

BACKGROUND (continued)

lock door is capable of being closed, and one emergency air lock door is closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The containment ventilation isolation system includes three subsystems. The Containment Purge System includes a 48 inch supply penetration and a 48 inch exhaust penetration. The Containment Pressure Relief System includes an 18 inch exhaust penetration. The Hydrogen Purge System includes a 12 inch supply penetration and a 12 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the Containment Purge System and Hydrogen Purge System supply and exhaust penetrations are secured in the closed position. The two valves in the Containment Pressure Relief System penetration can be opened continuously, but are closed automatically by the Engineered Safety Features Actuation System (ESFAS). None of the subsystems are subject to a Specification in MODE 5.

In MODE 6, large air exchangers are necessary to conduct refueling operations. The normal 48 inch Containment Purge System is used for this purpose, and all four valves are closed by the Containment Radiation Monitor in accordance with LCO 3.3.6, “Containment Ventilation Isolation Instrumentation."

The Containment Pressure Relief System remain operational in MODE 6, and both valves are also closed by the Containment Ventilation Isolation Instrumentation.

The Hydrogen Purge System is not normally used in MODE 6. However, all six of the twelve inch valves are also closed by the Containment Ventilation Isolation Instrumentation.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by a closed automatic isolation valve or manual isolation valve, or by a blind flange or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, 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. 1). Fuel handling accidents, analyzed in Reference 2, include dropping a single irradiated fuel assembly in either the containment or fuel building with no credit for isolation or filtration. The requirements of LCO 3.9.7, "Refueling Cavity Water Level," and the minimum decay time of the Technical Requirements Manual (Ref. 4) prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 2), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. Containment penetration closure is not required to meet the acceptance limits for offsite radiation exposure of 25% of 10 CFR 100 values (Ref 3).

Containment penetrations satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment ventilation penetrations, the personnel air locks, and the equipment hatch, which must be capable of being closed. For the OPERABLE containment ventilation penetrations, this LCO ensures that these penetrations are isolable by the Containment Ventilation Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic ventilation isolation valve closure function specified in the FSAR can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

Both containment personnel air lock doors may be open during movement of irradiated fuel or CORE ALTERATION, provided an air lock door is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that: 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the air lock following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of an open air lock can be quickly removed.

(continued)

BASES

LCO (continued)

The LCO is modified by a NOTE allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERNATIONS or movement of irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

The equipment hatch may be open during movement of irradiated fuel or CORE ALTERNATIONS provided the hatch is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERNATIONS, 2) specified individuals are designated and readily available to close the equipment hatch following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of the equipment hatch can be quickly removed.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the containment ventilation isolation system not capable of automatic actuation when the isolation valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open isolation valves will demonstrate that the required valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each required valve is capable of being closed by an OPERABLE automatic containment ventilation isolation signal.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. A surveillance before the start of refueling operations will provide two or three surveillance verifications during the applicable period for this LCO. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the environment.

SR 3.4.9.2

This Surveillance demonstrates that the necessary hardware, tools, and equipment are available to install the equipment hatch. The equipment hatch is provided with a set of hardware, tools, and equipment for moving the hatch from its storage location and installing it in the opening. The required set of hardware, tools, and equipment shall be inspected to ensure that they can perform the required functions.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete the fuel handling operations. The Surveillance is modified by a Note which only requires that the Surveillance be met for an open equipment hatch. If the equipment hatch is installed in its opening, the availability of the means to install the hatch is not required. The 7 day Frequency is adequate considering that the hardware, tools, and equipment are dedicated to the equipment hatch and not used for any other function.

SR 3.9.4.3

This Surveillance demonstrates that each required containment ventilation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal from a containment atmosphere gaseous

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.3 (continued)

monitoring instrumentation channel. The 18 month Frequency maintains consistency with other similar instrumentation and valve testing requirements. In LCO 3.3.6, the Containment Ventilation Isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 18 months a CHANNEL CALIBRATION is performed. These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

REFERENCES

1. FSAR, Section 15.7.4.

2. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.

3. NUREG-0797, Section 15.4.8, Supplement 22, January 1990.

4. Technical Requirements Manual

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the subsequent plate out of boron would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

The RHR System in MODE 6 satisfies criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

(continued)

BASES

LCO (continued)

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations 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 minimum required RCS boron concentration is maintained is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

Note

The acceptability of the LCO and the LCO Note is based on preventing boiling in the core in the event of the loss of RHR cooling. It has been determined, however, that when the upper internals package is in place in the reactor vessel there is insufficient communication with the water above the core for adequate decay heat removal by natural convection (see SMF-2002-2676). As a result boiling could occur in a relatively short time if RHR cooling is lost. As an interim measure, temporary administrative processes are implemented to reduce the risk of core boiling. The availability of additional cooling equipment, including equipment not required to be OPERABLE by the specifications, contributes to this risk reduction. This strategy is consistent with NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," for management of shutdown tasks to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications which can be used to provide the needed cooling. The plant staff assesses these cooling sources to assure that the desired level of minimal risk is maintained (frequently referred to as maintaining a desired defense in depth). The level of detail involved in the assessment will be commensurate with the equipment affected.

Because of its generic nature, any required TS and/or TS Bases changes will be determined by the industry Technical Specification Task Force (TSTF).

(continued)

BASES (continued)

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.7, "Refueling Cavity Water Level." Requirements for the RHR 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). RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition. Performance of Required Action A2 shall not preclude completion of movement of a component to a safe condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE

(continued)

BASES

ACTIONS

A.3 (continued)

6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures 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 the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

1. FSAR, Section 5.4.7.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the subsequent plate out of boron will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

The RHR System in MODE 6 satisfies criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order 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.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. An OPERABLE RHR loop must be capable of being realigned to provide an OPERABLE flow path.

(continued)

BASES (continued)

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR 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). RHR loop requirements in MODE 6 with the water level 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level."

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that 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 RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be

(continued)

BASES

ACTIONS

B.3 (continued)

closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment 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 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.6.2

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

REFERENCES

1. FSAR, Section 5.4.7.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies, within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3 and acceptance in Reference 6.

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.195 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for iodine. This relates to the assumption that 99.5% 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 the following fractions of the total fuel rod inventory (Ref. 1):

0.08 for I-131, 0.10 for Kr-85, 0.05 for all other iodines and noble gases.

The fuel handling accident analysis is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time as described in the Technical Requirements Manual (Ref. 7) prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 4, 5 and 6).

Refueling cavity water level satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 3.

(continued)

BASES (continued)

APPLICABILITY

LCO 3.9.7 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.15, "Fuel Storage Pool Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.195, May 2003.

2. FSAR, Section 15.7.4

3. NUREG-0800, Section 15.7.4.

4. 10 CFR 100.10.

(continued)

BASES

REFERENCES (continued)

5. Malinowski, D. D., Bell, M. J., Duhn, E., and Locante, J., WCAP-828, Radiological Consequences of a Fuel Handling Accident, December 1971.

6. NUREG-0797, Section 15.4.8, Supplement 22, January 1990.

7. Technical Requirements Manual.

TS BASES EFFECTIVE LISTING FOR SECTIONS

Revision Record:

Revision Number	Related TS Amendments (if any)	Date of Revision
Amendment 64 and Revision 1	A64 & A65	July 27, 1999
Errata to Amendment 64 and Revision 1	None	July 28, 1999
Revision 2	None	July 29, 1999
Revision 3	A66	August 31, 1999
Revision 4	A67	September 29, 1999
Revision 5	A69, A70 & A71	September 30, 1999
Revision 6	A72	October 7, 1999
Revision 7	None	November 24, 1999
Revision 8	A73	December 30, 1999
Revision 9	A75 & A76	April 23, 2000
Revision 10	A77	May 26, 2000
Revision 11	A79	September 19, 2000
Revision 12	A74 & A78	December 31, 2000
Revision 13	None	April 25, 2001
Revision 14	A85	May 18, 2001
Revision 15	A86	July 17, 2001
Revision 16	None	October 1, 2001
Revision 17	A88	November 1, 2001
Revision 18	A87	January 3, 2002
Revision 19	A92 & A93	March 25, 2002
Revision 20	None	March 27, 2002
Revision 21	A96	July 24, 2002
Revision 22	A97	August 15, 2002
Revision 23	A89	October 10, 2002
Revision 24	None	October 23, 2002
Revision 25	A102	February 28, 2003
Revision 26	A91	March 13, 2003
Revision 27	None	June 2, 2003
Revision 28	None	June 26, 2003
Revision 29	A105	August 21, 2003
Revision 30	A106	September 18, 2003
Revision 31	A107 & A108	October 2, 2003
Revision 32	None	December 18, 2003
Revision 33	None	March 11, 2004
Revision 34	A109 & A111	March 23, 2004
Revision 35	None	April 23, 2004
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TS BASES EFFECTIVE LISTING FOR SECTIONS

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Revision 47	A126	June 15, 2006
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Revision 49	A129	October 17, 2006
Revision 50	A127	November 16, 2006
Revision 51	None	December 14, 2006
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Revision 53	A136	April 11, 2007
Revision 54	A133	June 21, 2007
Revision 55	A137 and 138	July 24, 2007
Revision 56	A140, 141 and 142	February 28, 2008
Revision 57	A144 and 145	April 4, 2008
Revision 58	None	June 19, 2008

Section	Amendment No.
B 2.0	Revision 51
B 3.0	Revision 51
B 3.1	Revision 57
B 3.2	Revision 57
B 3.3	Revision 57
B 3.4	Revision 58
B 3.5	Revision 57
B 3.6	Revision 56
B 3.7	Revision 58
B 3.8	Revision 58
B 3.9	Revision 56
EL-1	June 19, 2008
EL-2	June 19, 2008
EL-3	June 19, 2008

REVISION 51

LDCR-TB-2006-2 (ACTN-MAN-2005-005086-07) (RAS):

Administrative change for software conversion only.

The type of changes include changes such (1) correction of spelling errors, (2) correction of inadvertent word processing errors from previous changes, and (3) style guide changes (e.g., changing from a numbered bullet list to an alphabetized bullet list and vice versa, change numbering of footnote naming scheme).

The entire Technical Specifications Bases will be reissued. For the text and tables there will be no change bars in the page margins for the editorial changes.

The list of effective pages is being replaced with a list of effective sections.

REVISION 52

LDCR-TB-2005-3 (EVAL-2005-001957-06) (RJK):

Insert the following paragraph prior to the last sentence under SR 3.3.1.7:

"SR 3.3.1.7 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing. "

Insert the following paragraph at the bottom of the page under SR 3.3.1.10:

"SR 3.3.1.10 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these

LDCR-TB-2005-3 (EVAL-2005-001957-06) (RJK) (continued):

devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing."

Revise the SG Low-Low level Nominal Trip Setpoint for Unit 1 from 25% to 38%.

Insert the following paragraph prior to the last sentence under SR 3.3.2.5:

"SR 3.3.2.5 for selected Functions is modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing. "

Insert the following paragraph at the end of the discusssion SR 3.3.2.9:

"SR 3.3.2.9 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose

LDCR-TB-2005-3 (EVAL-2005-001957-06) (RJK) (continued):

instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing."

Revise the SG High-High Level Nominal Trip Setpoint for Unit 1 from 82.4% to 84%.

Revise the SG Low-Low level Nominal Trip Setpoint for Unit 1 from 25% to 38%.

Revise the discussion under SR 3.4.5.2, SR 3.4.6.2 by:

Replacing "equal to or greater than 10%" with "equal to or greater than 38% (Unit 1) and equal to or greater than 10% (Unit 2)"

Replacing "less than 10%" with "less than 38% (Unit 1) and less than 10% (Unit 2)"

In the next to last paragraph under "APPLICABLE SAFETY ANALYSIS", replace "10%" with "38% (Unit 1) and 10% (Unit 2)".

In two locations in the first paragraph under "LCO", replace "greater than or equal to 10%" with "greater than or equal to 38% (Unit 1) and greater than or equal to 10% (Unit 2)".

At the end of the last sentence in the first paragraph on the page, replace "greater than or equal to 10%" with "greater than or equal to 38% (Unit 1) and greater than or equal to 10% (Unit 2)".

In the first paragraph under "ACTIONS A.1 and A.2", replace less than 10%" with "less than 38% (Unit 1) and less than 10% (Unit 2)"

In discussion under "SR 3.4.7.2" and SR 3.4.7.3", replace "greater than or equal to 10%" with "greater than or equal to 38% (Unit 1) and greater than or equal to 10% (Unit 2)".

REVISION 53

LDCR-TB-2007-2 (EVAL-2005-001869-06) (JDS):

Revises nominal trip setpoint for Unit 1 RWST Low-Low Level to 33.0% to reflect LA 129 by deleting the 45.0% setpoint specified as Unit 1 only and deleting the Unit 2 only applicability for the 33.0% setpoint. The revised setpoint will support resolution of GSI-191.

LDCR-TB-2005-5 (EVAL-2005-000224-02) (RAS):

In TS B 3.3.2 second paragraph of 5.c "Turbine Trip and Feedwater Isolation -- Safety Injection, insert "(See TB 3.7.3)" after the words "associated bypass valves"

In the TS B 3.6.3 ACTIONS discussion of C.1 and C.2, number 1, insert "Unit 2" in front of the words "Feedwater Preheater Bypass Lines"

1.) In TS B 3.7.3 Background section, replace the second sentence of the first paragraph which reads:

"Each FIV has a FIV Bypass Valve (FIBV) and a Feedwater Preheater Bypass Valve (FPBV) which are its associated bypass valves."

with the following two sentences,

"Each Unit 1 FIV has a FIV Bypass Valve (FIBV) which is its associated bypass valve. Each Unit 2 FIV has a FIV Bypass Valve (FIBV) and a Feedwater Preheater Bypass Valve (FPBV) which are its associated bypass valves. "

2.) Under the same section as above, but in the second sentence of the third paragraph, insert "Unit 2" in front of the words "preheater bypass valve" and "FIV is located"

1.) After the second sentence of the third paragraph of the TS B 3.7.3 BACKGROUND section, add the following sentence:

"On Unit 1, the AFW injection point is in the FW piping not connected to the main feedwater line."

2.) In the next sentence, replace the word "The" with "On Unit 2, the"

3.) In the next two sentences insert "Unit 2" before the words "preheater bypass valve"

4.) Make the remaining sentences into a new paragraph.

In the second sentence discussion of SR 3.7.5.3 of TS B 3.7.5, add the words "Unit 2" before the words "Feedwater Split Flow Bypass valves"

LDCR-TB-2006-4 (EVAL-2005-001957-16) (RJK):

RCS flow coastdown analysis is based on a momentum balance within the Reactor Coolant System and input values of the coastdown curve should only be validated by conducting the test again when changes are made to the RCS such that a change to the system flow characteristics have been made which might adversely affect the calculation of delay times associated with the low flow reactor trip circuitry. The primary driving force for flow coastdown is the momentum of the reactor coolant pumps, and the NSSS upgrade project does not impact the pump, motor, or flywheel such that a change in momentum input parameters is required. The current CPSES flow coastdown analysis was compared to the new analysis for the Delta76 steam generators which revealed that active loop flow will be higher with the RSGs, therefore, the changes to the RCS flow characteristics introduced by the installation of replacement SGs will not have an adverse affect on the Reactor Protection System low flow reactor trip circuitry delay times as assumed in the partial and complete loss of forced coolant flow accident analysis.

LDCR-TB-2007-3 (EVAL-2006-003263-03) (TJE):

Revise TSB SR 3.8.3.3, "Diesel Fuel Oil, Lube Oil, and Starting Air" surveillance requirements to accept new fuel oil with absolute specific gravity at 60/60 degree F of "greater than or equal to" 0.8156 and "less than or equal to" 0.8927 or an API gravity at 60 degree F of "greater than or equal to" 27 degrees and "less than or equal to" 42 degrees if the diesel fuel oil storage tanks will have a total tank absolute specific gravity at 60/60 degree F of "greater than or equal to" 0.8348 or an API gravity at 60 degree F of "less than or equal to" 38 degrees. CPSES current supplier of diesel fuel oil carries only ultra low sulfur diesel (ULSD) and no longer has low sulfur diesel (LSD) fuel available for purchase.

1.) In Surveillance Requirements discussion of SR 3.8.3.3, replace sentence that reads,

"The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion."

with the following sentence,

"The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion, and when added to the tank existing volume will maintain the tank volume absolute specific gravity range of "greater than or equal to" 0.8348 and "less than or equal to" 0.8927 at 60/60°F or an API gravity range of "greater than or equal to" 27° and "less than or equal to" 38° at 60°F

2.) Replace the second to last sentence which reads,

"These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days."

LDCR-TB-2007-3 (EVAL-2006-003263-03) (TJE) (continued):

with the following sentence,

"Tests a through d are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests a through d to exceed 31 days."

3.) In SR 3.8.3.3.b, replace the paragraph,

"Verify in accordance with the tests specified in ASTM D975-1981 (Ref. 6) that the sample has an absolue specific gravity at 60/60°F of > 0.8348 and < 0.8927 or an API gravity at 60°F of > 27° and < 38° when tested in accordance with ASTM D1298-1980 (Ref. 6), a kinematic viscosity at 40°C of > 1.9 centistokes and < 4.1 centistokes, and a flash poiint of > 125°F, and"

with the following paragraph

"Verify in accordance with the tests specified in ASTM D975-1981 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of "greater than or equal to" 0.8156 and "less than or equal to" 0.8927 or an API gravity at 60°F of "greater than or equal to" 27° and "less than or equal to" 42° when tested in accordance with ASTM D1298-1980 (Ref. 6), a kinematic viscosity at 40°C of "greater than or equal to" 1.9 centistokes and "less than or equal to" 4.1 centistokes, and a flash point of "greater than or equal to" 125°F,"

3.) In SR 3.8.3.3.c, delete the period and insert a comma

4) Add SR 3.8.3.3.d and e,

"d.) Verify by analysis that after the new fuel is added to the tank(s), the tank(s) will have an absolute specific gravity at 60/60°F of "greater than or equal to" 0.8348 and "less than or equal to" 0.8927 or an API gravity at 60°F of "greater than or equal to" 27° and "less than or equal to" 38°, and

e.) Within 31 days after new fuel is added to the tank(s), verify the sample has an absolute specific gravity at 60/60°F of "greater than or equal to" 0.8348 and "less than or equal to" 0.8927 or an API gravity at 60°F of "greater than or equal to" 27° and "less than or equal to" 38°."

LDCR-TB-2007-1 (EVAL-2003-002426-22) (JDS):

Revise the first paragrah under APPLICABLE SAFETY ANALYSIS by deleting the last sentence.

Replace the first four sentences of the second paragraph with the following:

"The containment was designed for an internal pressure load equivalent to 50 psig. The LOCA and SLB are examined under a variety of initial conditions to ensure that the containment design limit is not exceeded. Although only two cases can yield pressure

LDCR-TB-2007-1 (EVAL-2003-002426-22) (JDS) (continued):

and temperature peaks, there are several cases that are near these peaks; furthermore, the time to the maximum temperature or pressure also varies with the assumed initial conditions. The full spectrum of cases for both LOCA and SLB transients determines the envelopes for which plant equipment is qualified."

Justification:

Containment re-analysis performed as a result of the installation of the Replacement Steam Generators as documented in calculations RXE-LA-CP1-0/0-004 (MSLB) and RXE-LA-CP1-0/0-003 (LOCA). These two calculations demonstrate that the maximum containment pressure is less than the design pressure of 50 psig and less than the existing value of Pa as documented in TS 5.5.16.b.

LDCR-TB-2007-4 (EVAL-2005-001957-17) (RJK):

A design modification (FDA-2003-002426-03) is being made on the Unit 1 atmospheric relief valve (ARV) controllers to remove a single failure vulnerability that resulted in the disabling of two ARVs on intact SGs. Following the modification, the postulated single failure only disables a single ARV, leaving two ARVs on unaffected steam generators available to mitigate the effects of a steam generator tube rupture.

LDCR-TB-2005-9 (EVAL-2005-001957-8) (CBC):

TS Bases 3.7.10

Consistent with TSTF-448, Revision 3, "Control Room Habitability," (approved by the NRC on January 9, 2007) the TS actions and SRs in TS 3.7.10, "Control Room Emergency Filtration /Pressurization System (CREFS)," are revised and a new administrative controls program, TS 5.5.20, "Control Room Envelope Habitability Program," is added. The purpose of the changes is to ensure that CRE boundary operability is maintained and verified through effective surveillance and programmatic requirements, and that appropriate remedial actions are taken in the event of an inoperable CRE boundary. These changes were approved by NRC License Amendment 136. The associated TS Bases 3.7.10 are revised to be consistent with the LA 136.

REVISION 54

LDCR-TB-2005-7 (EVAL-2005-002551-1) (TJE):

1.) Replace the existing second sentence of SR 3.3.1.2 which reads,

" If the calorimetric exceeds the NIS and N-16 power indications by > 2% RTP, the NIS and N-16 functions are not declared inoperable, but the channel gains must be adjusted consistent with the calorimetric power."

with a new sentence which reads,

LDCR-TB-2005-7 (EVAL-2005-002551-1) (TJE) (continued):

"If the calorimetric exceeds the NIS or N-16 power indications by more than +2% RTP, the affected NIS and N-16 functions are not declared inoperable, but the channel gains must be adjusted consistent with the calorimetric power.

2.) After the first paragraph, add these next five paragraphs,

"If the NIS and N-16 power indications are normalized to within 2% RTP of the calorimetric power, and reactor power is then reduced, the NIS power indication will be lower than actual due to downcomer temperature shielding and neutron flux redistribution effects. The N-16 power indication will not be influenced by these effects. If a calorimetric measurement is then performed, using the Leading Edge Flow Meter (LEFM) to determine the feedwater flow, the NIS power indication may be normalized to the calorimetric power. Upon a subsequent return to near full power, the NIS power indication may become higher than actual due to the same downcomer temperature shielding and neutron flux redistribution effects. Again, the N-16 power indication will not be influenced by these effects.

The uncertainty associated with the calorimetric power measurement using the LEFM is independent of the reactor power level down to less than 20% RTP. However, if the LEFM is unavailable, and the calorimetric power measurement is performed using the feedwater venturis as the source of the feedwater flow information, additional considerations are required.

If the venturi-based calorimetric is performed at reduced power (< 55% RTP), adjusting the Power Range indication in the increasing power direction will assure a reactor trip below the safety analysis limit. Making no adjustment to the Power Range channel in the decreasing power direction due to a reduced power venturi-based calorimetric assures a reactor trip consistent with the safety analyses. Based on plant calculations, 55% RTP is the lowest power at which the calorimetric uncertainty, performed with the feedwater venturis and the precision set of transmitters, results in an uncertainty of less than 2%.

This allowance does not preclude making indicated power adjustments, if desired, when the venturi-based calorimetric heat balance calculation is less than the NIS or N-16 channel outputs. To provide close agreement between indicated power and to preserve operating margin, the NIS and N-16 power indications are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the NIS or N-16 power indications are adjusted in the decreasing power direction based on a reduced power venturi-based calorimetric (< 55% RTP). This action may introduce a non-conservative bias at higher power levels which may result in a reactor trip above the safety analysis limit. The most significant cause of the potential non-conservative bias is the decreased accuracy of the venturi-based calorimetric measurement at reduced power conditions. The primary error contributor to the instrument uncertainty for a secondary side venturi-based power calorimetric measurement is the feedwater flow measurement, which is a differential pressure (delta P) measurement across a feedwater venturi. While the measurement uncertainty remains constant in delta P as power decreases, when translated into flow, the uncertainty increases as a square term. Thus, a 1% flow error at 100% power can approach a 10% flow error at 30% RTP even though the delta P error has not changed.

LDCR-TB-2005-7 (EVAL-2005-002551-1) (TJE) (continued):

An evaluation of extended operations at reduced power conditions would likely conclude that it is prudent to administratively adjust the setpoint of the Power Range Neutron Flux - High bistables to less than or equal to 90% RTP when: 1) the Power Range channel output is adjusted in the decreasing power direction due to a reduced power venturi-based calorimetric below 55% RTP; or 2) for a post refueling startup (consistent with the Bases for SR 3.4.1.4). The evaluation of extended operation at reduced power conditions would also likely conclude that the potential need to adjust the indication of the Power Range Neutron Flux in the decreasing power direction is quite small, primarily to address operation in the intermediate range about P-10 (nominally 10% RTP) to allow enabling of the Power Range Neutron Flux - Low setpoint and the Intermediate Range Neutron Flux reactor trips. Before the Power Range Neutron Flux - High bistables are reset to their nominal value high setpoint, the NIS or N-16 power indication adjustment must be confirmed based on a LEFM-based calorimetric or on a venturi-based calorimetric performed at greater than or equal to 55% RTP.

NOTE: These additional words will run over to page 54

1.) In the existing first paragraph on page B 3.3-53, delete the first and second sentences, "Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS or N-16 power indications shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS or N-16 power indications and the calorimetric is > 2% RTP."

2.) Currently, the third sentence on this page reads,

"The second Note clarifies that this Surveillance is required only if reactor power is > or = to 15% RTP and that 24 hours are allowed for performing the first Surveillance after reaching 15% RTP."

Delete the word "second" so that the sentence reads,

"The Note clarifies that this Surveillance is required only if reactor power is > or = to 15% RTP and that 24 hours are allowed for performing the first Surveillance after reaching 15% RTP."

3.) In the same paragraph and page, replace the sentence,

"At lower power levels calorimetric data are inaccurate."

with the following sentence,

"A power level of 15% RTP is chosen based on plant stability; i.e., the turbine generator is synchronized to the grid and rod control is in the automatic mode."

4.) In the last sentence of the second paragraph, the sentence currently reads:

"Together these factors demonstrate the change in the absolute difference between NIS, N-16 and heat balance calculated powers rarely exceeds 2% in any 24 hour period."

LDCR-TB-2005-7 (EVAL-2005-002551-1) (TJE) (continued):

Revise sentence to read:

"Together these factors demonstrate that a difference of more than +2% RTP between the calorimetric heat balance calculation and NIS Power Range channel output or N-16 Power Monitor output is not expected in any 24 hour period."

5.) Add the following sentence to the end of the first paragraph of SR 3.3.1.3 also on page B 3.3-54,

"The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is (greater than or equal to) 3%.

6.) Delete the first two sentences of the first paragraph on page B 3.3-54 which reads,

"Two notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is (greater than or equal to) 3%."

7.) Currently, the third sentence says,

"Note 2 clarifies that the Surveillance is required only if reactor power is (greater than or equal to) 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP."

Replace the words "Note 2" with "A Note" such that the sentence reads,

"A Note clarifies that the Surveillance is required only if reactor power is (greater than or equal to) 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP."

8.) Currently, the forth sentence reads,

"Note 2 allows power ascensions and associated testing to be conducted in a controlled and orderly manner, at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE."

Replace the words "Note 2" with the words "The Note" such that the sentence reads:

The Note allows power ascensions and associated testing to be conducted in a controlled and orderly manner, at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE."

This LDCR adds a large amount of verbiage to the Bases; therefore, it was necessary to add this new page for the overflow.

REVISION 55

LDCR-TB-2005-11 (EVAL-2005-001822-04-01) (RAS):

Revise first paragraph under BACKGROUND as follows:

"The maximum dose to the whole body and the thyroid that an individual at the Exclusion Area boundary can receive for 2 hours following an accident, or at the Low Population Zone outer boundary for the radiological release duration, is specified in 10 CFR 100.11 (Ref. 1). Doses to the Control Room operators must be limited per GDC 19. The limits on specific activity ensure that the doses are appropriately limited during analyzed transients and accidents."

Revise last paragraph under BACKGROUND disucssion as follows:

"The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and Control Room doses meet the appropriate acceptance criteria in the Standard Review Plan. The limits in the LCO are specific to CPSES due to the implementation of the alternate steam generator tube repair criteria."

Revise first paragraph under APPLICABLE SAFETY ANALYSES as follows:

"The LCO limits on the specific activity of the reactor coolant ensures that the resulting offsite and Control Room doses meet the appropriate Standard Review Plan acceptance criteria following a SGTR or a MSLB accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at, or more conservative than, the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm. The MSLB safety analysis (Ref. 3) assumes the specific activity of the reactor coolant at, or more conservative than, the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 27.8 gpm in the affected steam generator and 450 gpm combined in the unaffected steam generators. The safety analysis for both accidents assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity."

In the first paragraph, insert "and SGTR" after "MSLB" and delete the sentence which reads "However, the SGTR accident analysis consequences are significant."

Revise the second paragraph to read as follows:

"Each of the above analyses must consider two cases of reactor coolant specific activity. One case assumes specific activity at 0.45 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases, by a factor of 500 or 335, the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a MSLB or SGTR, respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre accident iodine spike caused by an RCS transient. In both cases, the noble gas specific activity is assumed to be the equivalent of 1% fuel defects which corresponds to 715 μCi/gm DOSE EQUIVALENT XE-133."

LDCR-TB-2005-11 (EVAL-2005-001822-04-01) (RAS) (continued):

In the fourth and sixth sentences in the fourth paragraph replace "cooldown ends" with "RHR system is placed in service".

In the last paragraph, 2nd sentence, replace "the limits shown in Figure 3.4.16-1, in the applicable specification," with "60.0 micro-curies per gram DOSE EQUIVALENT I-131" and delete the last sentence in its entirety.

Under the discussion of the LCO, delete the entire first paragraph and replace with the following:

"The iodine specific activity in the reactor coolant is limited to 0.45 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 500 μCi/gm DOSE EQUIVALENT XE-133, as contained in SR 3.4.16.2 and SR 3.4.16.1 respectively. The limits on specific activity ensure that offsite and Control Room doses will meet the appropriate Standard Review Plan acceptance criteria."

In the second paragraph, replace "2 hour site boundary" with "calculated" in the first sentence. Revise the second sentence as follows:

"Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a MSLB or SGTR, lead to doses that exceed the SRP acceptance criteria."

Replace the two paragraphs under the APPLICABILITY discussion with the following:

"In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of an SGTR and an MSLB to within the SRP acceptance criteria.

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, monitoring of RCS specific activity is not required."

Under the discussion of ACTIONS A.1 and A.2, in the first paragraph replace "the ACTIONS" in the second sentence with "Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met." and relocate the entire paragraph to after the existing third paragraph.

Under the discussion of ACTIONS A.1 and A.2, in the second paragraph first sentence replace "limits of Figure 3.4.16-1 are not exceeded" with "specific activity is less than or equal to 60.0 micor-curies per gram".

Under the discussion of ACTIONS A.1 and A.2, in the third paragraph second sentence replace "is required, if the limit violation resulted from normal iodine spiking." with "acceptable since it is expected that, if there were no iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a MSLB or SGTR occurring during this time period."

LDCR-TB-2005-11 (EVAL-2005-001822-04-01) (RAS) (continued):

Under the diiscussion of B.1, replace both existing paragraphs with the following:

"With the DOSE EQUIVALENT XE-133 in excess of the allowed limit, DOSE EQUIVALENT XE-133 must be restored to within limits within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a MSLB or SGTR occurring during this time period.

A NOTE permits the use of of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation."

Revise the header "C.1" to "C.1 and C.2" and revise the paragraph under C.1 as follows:

"If the Required Action and the associated Completion Time of Condition A or B is not met or if the DOSE EQUIVALENT I 131 is > 60.0 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems."

Revise the first and second paragraphs under the discussion of SR 3.4.16.1 as follows:

"SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in noble gas 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 7 day Frequency considers the unlikelihood of a gross fuel failure during the time."

Insert the following two paragraphs after the existing paraghs under the discussion of SR 3.4.16.1:

"If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 in Specification 1.1, Definitions," is not detected, it should be assumed to be present at the minimum detectable activity.

LDCR-TB-2005-11 (EVAL-2005-001822-04-01) (RAS) (continued):

The NOTE modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1."

Revise the paragraph under SR 3.4.16.2 as follows:

"This Surveillance is performed in MODE 1 only to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change = 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results."

Insert the following paragraph as the last paragraph under 3.4.16.2:

The NOTE modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

Delete both paragraphs under the discussion of SR 3.4.16.3 and insert "DELETED".

LDCR-TB-2005-12 (EVAL-2005-003468-03) (RAS):

In last sentence on the page, change "12 hours" to "24 hours".

Original CP TS were developed with the Action for one SI Sequencer the same as the Action for one inoperable SI logic train which was a 6 hour Completion time. When TS were converted to ITS, CP followed in part the Standard TS, Nureg 1431. This moved the sequencer from TS 3.3.2 to 3.8.1 and adopted a 12 hour Completion Time which was in the STS although it is a plant specific value. Recently in License Amendment 114, the Completion Time for SI logic inoperable (as well as the other SSPS logics) was extended to 24 hours. Based on a similar philosophy as used for the original TS, the impact of an inoperable SI sequencer would be less than or equal to an inoperable train of SI logic (or the whole SSPS train).

REVISION 56

LDCR-TB-2006-13 (EVAL-2005-003335-01) (CBC):

TS Bases SR 3.4.10.1 and the References at the end of B 3.4.10 are updated. The proposed changes delete reference to Section XI of the Code and incorporate reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.4.11.1 is updated. The proposed changes delete reference to Section XI of the Code and incorporate reference

LDCR-TB-2006-13 (EVAL-2005-003335-01) (CBC) (continued):

to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): References at the end of TS Bases 3.4.11 are updated. The proposed changes delete reference to Section XI of the Code and incorporate reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.4.12.4 is updated. The proposed change delete reference to Section XI of the Code and incorporate reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References at the end of TS Bases 3.4.12 is updated. The proposed change deletes the reference to Section XI of the Code and incorporate reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.4.14.1 is updated. The proposed change deletes a reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References for TS Bases SR 3.4.14 are updated. The proposed change deletes the reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.5.2.4 is updated. The proposed change deletes the reference to Section XI of the Code and incorporates the reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.6.6.4 is updated. The proposed change deletes the reference to Section XI of the Code and incorporates the reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References for TS Bases SR 3.6.6 are updated. The proposed change deletes the reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear

LDCR-TB-2006-13 (EVAL-2005-003335-01) (CBC) (continued):

Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.7.1.1 is updated. The proposed change deletes the reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References for TS Bases SR 3.7.1.1 is updated. The proposed change deletes a reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.7.5.2 and SR 3.7.5.3 are updated. The proposed changes delete reference to Section XI of the Code and incorporate reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References for TS Bases SR 3.7.5 are updated. The proposed change deletes the reference to Section XI of the Code and incorporates the reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): TS Bases SR 3.8.6.1 is updated. The proposed change deletes the reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

EVAL-2005-003335-01 (LDCR-TB-2006-13): The References for TS Bases SR 3.8.1 are updated. The proposed change deletes the reference to Section XI of the Code and incorporates a reference to the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code). This change is for consistency with LAR-06-006 (TSTF-479 and TSTF-497).

LDCR-TB-2006-14 (EVAL-2006-003110-01) (CBC):

EVAL-2006-003110-01 (LDCR-TB-2006-14): Update TS Bases SR 3.6.1.1 to be consistent with change to TS 5.5.16 (LAR-06-010).

LDCR-TB-2006-12 (EVAL-2006-003850-01) (CBC):

Deletes discussion of second Completion Times from TSB 3.7.5, ACTION A.1. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.7.5, ACTION B.1. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.8.1, ACTION A.3. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.8.1, ACTION B.4. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.8.9, ACTION A.1. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong

LDCR-TB-2006-12 (EVAL-2006-003850-01) (CBC) (continued):

disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.8.9, ACTION B.1. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

EVAL-2006-003850-01 (LDCR-TB-2006-012): Deletes discussion of second Completion Times from TSB 3.8.9, ACTION C.1. The TS Bases is updated to be consistent with LAR-06-012 which deletes second Completion Times from TS (TSTF-439-R2). A second Completion Time was included in the TSs for certain Conditions / Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single contiguous failure to meet the Limiting Condition for Operation (LCO). The Maintenance Rule and the Reactor Oversight Process now provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second Completion Times were designed to prevent.

LDCR-TB-2006-15 (EVAL-2005-002856-05) (JDS):

The standard equations are based on the linear relationship between the detector current (or excore axial offset) and incore asial offset (AO). The data from previous calibrations was normalized and used to determine standard slope and intercept (and therefore a standard excore calibration gain) that describes the linear relationship. A review of the multipoint excore detector calibrations performed at CPSES to date indicates that there is only a small variation in the excore detector calibration gain between NIS channels, burnup cycles, and as a function of burnup within each cycle. This is expected because the gain is primarily a function of the fixed geometry between the excore detectors and the core. The calculation demonstrated that the use of the standard in place of a traditional multipoint calibration supports the uncertainties used in the Safety Analysis.

LDCR-TB-2007-6 (EVAL-2004-002063-14) (JDS):

In the first paragraph of TS Bases Background section B 3.3.6, replace the sentence,

"The Hydrogen Purge System is a supplementary system for the electric hydrogen recombiners and is operated for hydrogen dilution in the containment following a LOCA."

with the following words,

"The Hydrogen Purge System may only be used with the reactor shutdown and containment pressure less than 5 psig."

LDCR-TB-2007-6 (EVAL-2004-002063-14) (JDS) (continued):

In TS Bases Background section B 3.6.3 under "Hydrogen Purge System (12 inch purge valves)", replace the sentence,

"The Hydrogen Purge System is a supplementary system for the electric hydrogen recombiners and operated for hydrogen dilution in the containment following a LOCA once pressure is below 5 psig. "

with the following words,

"The Hydrogen Purge System may only be used with the reactor shutdown and containment pressure less than 5 psig."

LDCR-TB-2007-7 (EVAL-2004-002698-02) (RAS):

In the next to last paragraph under the discussion of the LCO Bases, change required minimum volume for the CST from "249,100" gallons to "241, 000" gallons.

LDCR-TB-2007-8 (EVAL-2007-001962-02) (RAS):

Revise the 3rd paragraph of the discussion of LCO 3.4.11 as follows:

"An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when either of the following plant conditions dictate closure of the block valve to limit leakage:

A. The automatic control system cannot maintain Pressurizer pressure and level within the assumed accident analysis limits (i.e., +/-30 psig of setpoint for pressure and +/- 5% of setpoint for level), or

B. RCS identified leakage cannot be maintained less than the limits of LCO 3.4.13 without closure of the associated PORV block valve."

LDCR-TB-2007-11 (EVAL-2006-000629-03) (TJE):

Both TS LCO 3.9.4 and TS LCO 3.9.7 limit the consequences of a fuel handling accident (FHA) in containment by ensuring barriers exist to limit the potential fission product release. The APPLICABLE SAFETY ANALYSES sections of these TS Bases discuss additional requirements of the FHA analysis that ensure the dose limits of 10CFR100 are met, particularly the required minimum decay time of 100 hours prior to core alterations. The reference for this decay time requirement is TR 13.9.31, however these TS Bases do not clearly document this relationship. The proposed change will remove the value (100 hours) and replace with a reference to the Technical Requirements Manual. The decay time requirement is not changed by the proposed change.

LDCR-TB-2007-11 (EVAL-2006-000629-03) (TJE) (continued):

Both TS LCO 3.7.15 and TS LCO 3.9.7 limit the consequences of a FHA by ensuring sufficient water level exists above the damaged spent fuel assembly to assist in the retention of iodine fission products. The APPLICABLE SAFETY ANALYSES sections of these TS Bases discuss assumptions of the FHA analysis as described in Regulatory Guide 1.25. These assumptions have been revised following the adoption and use of Regulatory Guide 1.195 by CPNPP for performing FHA analyses. The proposed activity revises the assumptions of the APPLICABLE SAFETY ANALYSES section as well as the RG reference located within the REFERENCES section as shown in the attached markup. The proposed changes will correctly document the guidance and use of RG 1.195.

The proposed LDCR is administrative in nature as it attempts to more clearly document the relationship between TS Bases 3.9.4, 3.9.7, TR 13.9.31, and the FHA analysis. This change allows for future revision of TR 13.9.31 without also revising the TS Bases. The decay time requirement is not changed by this activity.

The proposed LDCR also revises B 3.7.15 and B 3.9.7 to correctly document the guidance and use of RG 1.195. This change is an administrative correction as the use of RG 1.195 has been previously approved.

On page B 3.9-14, in the Applicable Safety Analyses, delete "100 hours" and insert "the Technical Requirements Manual (Ref. 4)"

In the Reference section, on page B 3.9-17, add Reference 4 which will read, "4. Technical Requirements Manual"

In the Applicable Safety Analyses section on page B 3.9-25:

A.) In the first paragraph:

1.) In the first sentence, change the reference from Regulatory Guide "1.25" to "1.195"

2.) In the second sentence,

a.) delete "(Regulatory Position C.1.c of Ref. 1)"

b.) change "100" to "200"

c.) delete "Regulatory Position C.1.g of"

3.) In the third sentence, delete "99%" and insert "99.5%"

4.) In the fourth sentence,

a.) delete "10%" and insert "the following fractions"

b.) delete "iodine"

LDCR-TB-2007-11 (EVAL-2006-000629-03) (TJE) (continued):

c.) delete "." and insert ":" after "(Ref. 1)"

d.) add the following list after "(Ref. 1)"

"0.08 for I-131, 0.10 for Kr-85, 0.05 for all other iodines and noble gases"

B.) In the second paragraph of the second sentence, delete "of 100 hours" and insert "as described in the Technical Requirements Manual (Ref. 7)"

In the Refereence section on page B 3.9-26,

a.) in Reference 1, delete "1.25, March 23, 1972." and insert "1.195, May 2003."

b.)add another reference "7. Technical Requirements Manual"

In the Applicable Safety Analyses on page B 3.7-69 of the first sentence, change "100" to "200" and "1.25" to "1.195"

In the Reference section on page B 3.7-71 of Reference 4, delete "1.25, Rev. 0." and insert "1.195, May 2003."

<u>REVISION 57</u>

LDCR-TB-2007-11 (EVAL-2006-000629-03) (JDS):

Revise to include the use of the Power Distribution Measurement System (Beacon) and Relaxed Axial Offset Control (RAOC) to implement Westinghouse methodology.

LDCR-TB-2007-9 (EVAL-2007-002367-02) (JDS):

Revise TS Bases 3.3.1 description to reflect the identification of the Nominal Trip Setpoint (NTSP) as the Limiting Safety System Setpoint, consistent with the guidance presented in TSTF-493, Revision 2 and Regulatory Information Summary 06-17, for the reactor trip functions.

Revise TS Bases to reflect the identification of the Nominal Trip Setpoint (NTSP) as the Limiting Safety System Setpoint, consistent with the guidance presented in TSTF 493, Revision 2 and Regulatory Information Summary 06-17, for the reactor trip functions identified above. Discuss application of footnote (r) to the Functional Units consistent with the guidance presented in TSTF 493, Revision 2, and Regulatory Information Summary 06-17.

Provide nominal trip setpoint for Overpower N-16 and add note to keep Setpoint for Unit 1 Cycle 13 at 110% RTP.

LDCR-TB-2007-9 (EVAL-2007-002367-02) (JDS) (continued):

Revise TS Bases to reflect the identification of the appropriate Nominal Trip Setpoint (NTSP) (and exceptions) as the Limiting Safety System Setpoint, consistent with the guidance presented in TSTF 493, Revision 2 and Regulatory Information Summary 06-17, for the reactor trip functions identified above. Describe methods used to calculate nominal trip setpoints for exceptions.

Describe methodology for determining allowable values for Nominal Trip Setpoints exceptions. Also adds direction (note q) for reset of instrument channel setpoint within the as-l;eft tolerance band. Also discusseds the applicability of notes Q and R for specific functions will begin after Cycle 13 for Unit 1.

Revise T1 (tau 1) Steam Generator Line Pressure - Low and add note retaining the original T1 for Cycle 13 of Unit 1.

Clarify that an increase in water may be either provide a benefit or penalty for peak clad temperature, depending on the transient.

Added turbine trip assuming primary system pressure control to Technical Specification Bases for completeness..

Added clarification tha a simple heat balance calculation may be used to determine primary system power to prevent secondary system overpressurization.

Clarify that not assuming failure to open on demand is passive failure mode.

Added discussion on the heat balance used for calculation of the maximum allowable power level for main steam safety valves setpoints.

Updated information regarding the roll of Auxiliary Feedwater in the small break LOCA to indicate that does not have a significant impact.

REVISION 58

LDCR-TB-2008-1 (EVAL-2007-003482-03) (TJEW):

Currently, Bases SR 3.8.3.3.f reads,

Within 31 days after addition to the tank(s), verify the sample has an absolute specific gravity at 60/60"degrees"F of "greater than or equal to" 0.8348 and "less than or equal to" 0.8927 or an API gravity at 60"degrees"F of "greater than or equal to" 27"degrees" and "less than or equal to" 38"degrees".

Replace the words "the sample" with the words "by sampling the appropriate storage tank(s) that the fuel in the tank(s) "

LDCR-TB-2008-2 (EVAL-2008-000497-01) (RAS):

In the second sentence under discussion of SR 3.4.5.2, correct the "equal to or greater than" symbols prior to 38% for Unit 1 and prior to 10% for Unit 2.

In the second sentence under discussion of SR 3.4.6.2, correct the "equal to or greater than" symbols prior to 38% for Unit 1 and prior to 10% for Unit 2.

In the first paragraph under discussion of LCO, correct the "equal to or greater than" symbols prior to 38% for Unit 1 and prior to 10% for Unit 2 in two places.

In the first paragraph under discussion of APPLICABILITY, correct the "equal to or greater than" symbols prior to 38% for Unit 1 and prior to 10% for Unit 2.

In the first sentence under discussion of SR 3.4.7.2, insert "equal to or greater than 38% (Unit 1) and" just prior to the existing equal to or greater than symbol and insert "(Unit 2)" immediately after the existing "10%".

In the third sentence under discussion of SR 3.4.7.3, insert "equal to or greater than 38% (Unit 1) and" just prior to the existing equal to or greater than symbol and insert "(Unit 2)" immediately after the existing "10%".

In the second sentence under discussion of the LCO, correct the misspelling of the word "line" by deleting the extra letter "el" at the beginning of the word.