Bases

Joseph M. Farley Nuclear Plant
Units 1 and 2

Related to:
Docket Nos. 50-348 and 50-364
Appendix A to
License Nos. NPF-2 and NPF-8

NOTE

The Bases contained in the succeeding pages summarize the reasons for the associated Specifications but, in accordance with 10 CFR 50.36, are not a part of the Technical Specifications.

Changes to the Bases are controlled by the Technical Specifications (TS) Bases Control Program, 5.5.14, in the Administrative Controls section of the Technical Specifications.

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that 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 on the limiting fuel rod 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 main steam safety valves prevents violation of the reactor core SLs.

BASES

APPLICABLE SAFETY ANALYSES

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

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

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

In meeting the DNB design criterion, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, and computer codes must be considered. As described in the FSAR, the effects of these uncertainties have been statistically combined with the correlation uncertainty to determine design limit DNBR values that satisfy the DNB design criterion.

Additional DNBR margin is maintained by performing the safety analyses to a higher DNB limit. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility.

The Reactor Trip System Functions (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions (i.e., resulting from a Condition I or II event) for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

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

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

(continued)

BASES

SAFETY LIMITS

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

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

b. The hottest fuel pellet in the core must 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 and Overpower ΔT 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 the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures 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 operations, normal operational transients, and AOOs.

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 main steam 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. Setpoints 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

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.

BASES

REFERENCES

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

2. FSAR, Section 7.2.

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 coolant pressure 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 2500 psia. 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 were hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there was 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 50.67, “Accident Source Term” (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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System Functions (Ref. 5), 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 (Ref. 5). 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 line atmospheric relief valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valve.

SAFETY LIMITS

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

BASES

SAFETY LIMIT VIOLATIONS

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 50.67, “Accident Source Term,” limits (Ref. 4).

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.

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 50.67.
5. FSAR. Section 7.2.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 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, unless otherwise specified. 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

(continued)

BASES

LCO 3.0.2 (continued)

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 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.

BASES

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.

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 enter 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. The LCO is no longer applicable.

(continued)

BASES

LCO 3.0.3 (continued)

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

d. 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 entering the next lower MODE applies. If a lower MODE is entered in less time than allowed, however, the total allowable time to enter MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is entered in 2 hours, then the time allowed for entering MODE 4 is the next 11 hours, because the total time for entering 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 enter 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 3.7.13, "Fuel Storage Pool Water Level." LCO 3.7.13 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.13 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.13 of "Suspend movement of irradiated fuel assemblies in the fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

BASES

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 either LCO 3.0.4a, LCO 3.0.4b, or LCO 3.0.4c.

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

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified in condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION (“Required Action and associated Completion Time not met”) allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

LCO 3.0.4b 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.

(continued)

BASES

LCO 3.0.4 (continued)

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 be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4b, 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 3.0.4b 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 3.0.4b risk assessments do not have to be documented.

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 3.0.4b 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

(continued)

BASES

LCO 3.0.4 (continued)

be more important to risk and use of the LCO 3.0.4b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4b by stating that LCO 3.0.4b is not applicable.

LCO 3.0.4c 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 3.0.4c 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 3.0.4b usually only consider systems and components. For this reason, LCO 3.0.4c is typically applied to Specifications which describe values and parameters (e.g., RCS Specific Activity), 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 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

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BASES

LCO 3.0.4 (continued)

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. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel. Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition 1) to prevent the trip function from occurring during the performance of required testing on another channel

(continued)

BASES

LCO 3.0.5 (continued)

in the other trip system, or 2) 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.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

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

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BASES

LCO 3.0.6 (continued)

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.

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. The following examples are provided for illustration:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or (EXAMPLE B3.0.6-1).

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or (EXAMPLE B3.0.6-2).

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable. (EXAMPLE B3.0.6-3)

<u>EXAMPLE B3.0.6-1</u>
If System 2 of Train A is inoperable, and System 5 of Train B is inoperable, a loss of safety function exists in supported System 5.

(continued)

BASES

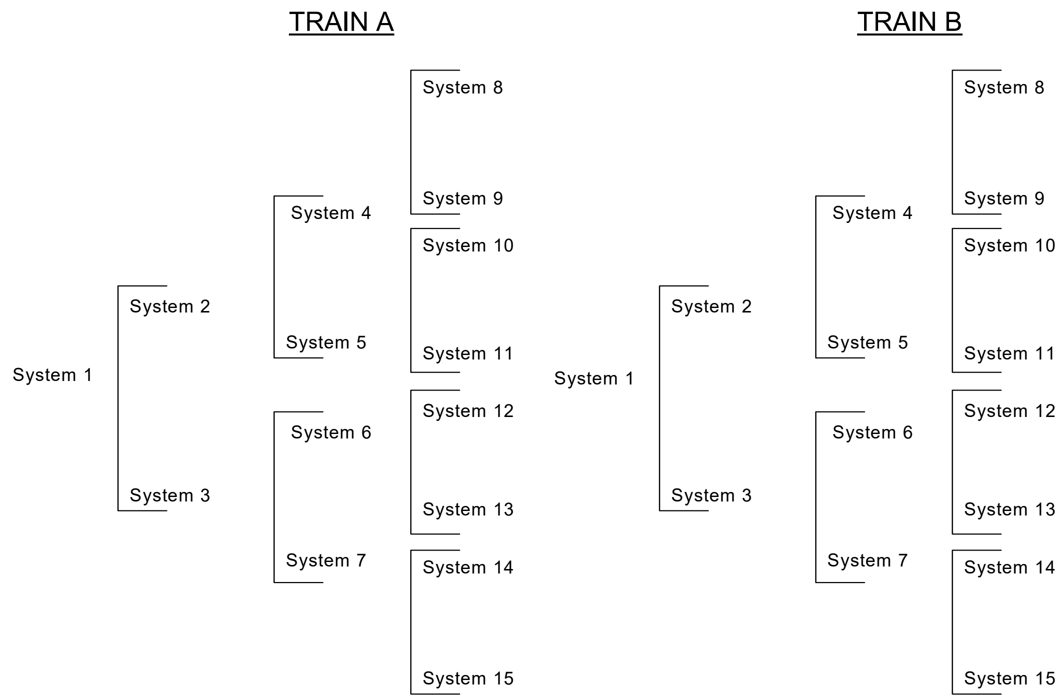
LCO 3.0.6 (continued)

EXAMPLE B3.0.6-2
If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11 which is in turn supported by System 5.

EXAMPLE B3.0.6-3
If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

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

EXAMPLES



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

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BASES

LCO 3.0.6 (continued)

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

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception 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.

LCO 3.0.8

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

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BASES

LCO 3.0.8 (continued)

repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

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

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

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

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

BASES

LCO 3.0.9

LCO 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support functions(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

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

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories.

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

(continued)

BASES

LCO 3.0.9 (continued)

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, RG 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, Revision 4A, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related supported function(s) must be declared inoperable and the associated LCOs declared not met. This 24-hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24-hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

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 3.0.2 and SR 3.0.3 apply in Chapter 5 only when invoked by a Chapter 5 Specification.

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.

(continued)

BASES

SR 3.0.1 (continued)

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

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

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).

When a Section 5.5, “Programs and Manuals,” specification states that the provisions of SR 3.0.2 are applicable, a 25% extension of the testing interval, whether stated in the specification or incorporated by reference, is permitted.

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. Examples

(continued)

BASES

SR 3.0.2 (continued)	of where SR 3.0.2 does not apply are the Containment Leakage Rate Testing Program required by 10 CFR 50, Appendix J, and the inservice testing of pumps and valves in accordance with applicable American Society of Mechanical Engineers Operation and Maintenance Code, as required by 10 CFR 50.55a. These programs establish testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot, in and of themselves, extend a test interval specified in the regulations directly or by reference. As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner. The provisions of SR 3.0.2 are not intended to be used repeatedly 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 performed 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. When a Section 5.5, “Programs and Manuals,” specification states that the provisions of SR 3.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 3.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 3.0.2 if invoked by the Section 5.5 specification). This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with Required Actions or other remedial measures that might preclude performance of the Surveillance.

(continued)

BASES

SR 3.0.3 (continued)

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

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

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

SR 3.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 3.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective

(continued)

BASES

SR 3.0.3 (continued)

evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

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 repeatedly 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.

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 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 in 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 entering 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.

(continued)

BASES

SR 3.0.4 (continued)

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

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 trip 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 provided 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 boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The Chemical and Volume Control System 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.

BASES

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) 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 trip.

For MODE 5, the primary Safety Analysis that relies on the SDM limits is the boron dilution analysis.

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 less than 200 cal/gm, thus meeting the NRC acceptance criteria of ≤ 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.

An Operating Procedure (Ref. 5) assures sufficient operator action time for the mitigation of an uncontrolled boron dilution event (Ref. 3) in MODE 5. This procedure is independent of SDM and uses the RHR system flowrate, and the calculated critical boron concentration to specify a minimum allowable boron concentration.

The most limiting accident for the SDM requirements is based on a guillotine break of a main steam line (MSLB) inside containment initiated at the end of core cycle life with RCS average temperature at no-load operating temperature, 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

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APPLICABLE SAFETY ANALYSES (continued)

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 RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value 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 that the Safety Limit (SL) requirement of SL 2.1.1 is met.

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

a. Inadvertent boron dilution; and

b. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis (Ref. 3), 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. For each cycle of operation at Farley Nuclear Plant, the minimum boron concentrations that are required in MODES 4 and 5 to allow 15 minutes operator action time are given in the Nuclear Design Report for that cycle.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

SDM satisfies Criterion 2 of 10 CFR 50.36(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.

With T_{avg} less than 200°F, the reactivity transients resulting from a postulated steam line break cooldown are minimal, and a 1% delta k/k SHUTDOWN MARGIN provides adequate protection.

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 (Ref. 2) and the boron dilution (Ref. 3) accidents 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 50.67, “Accident Source Term," 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 applicable.

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.”

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of Immediately is adequate to ensure prompt operator action to correctly align and start the required

(continued)

ACTIONS

A.1 (continued)

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 possible, the flowpath of choice would utilize 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.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration may approach or exceed 2000 ppm. For example, if the emergency boration path is used, the CVCS is capable of inserting negative reactivity at a rate of approximately 65 pcm/min when the RCS boron concentration is 1000 ppm and approximately 75 pcm/min when the RCS boron concentration is 100 ppm.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. 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.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

2. FSAR, Section 15.4.2.

3. FSAR, Section 15.2.4.

4. 10 CFR 50.67.

5. Letter from D.E. McKinnon to L.K. Mathews, “Operating Procedure for Mode 4/5 Boron Dilution,” 90 AP*-G-0041, July 6, 1990.

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 (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

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

(continued)

BASES

BACKGROUND (continued)

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.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 life (BOL) 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 BOL, 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 BOL, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOL 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 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the 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 ± 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.

(continued)

BASES

LCO (continued)

When measured core reactivity is within 1% Δk/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") ensure that fuel movements are performed within the bounds of the safety 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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% Δk/k limit, 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. If the SDM for MODE 3 is not met, then the boration required by 3.1.1.1 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.

BASES

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 BOL. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle life (BOL) 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 BOL within the range analyzed in the plant accident analysis. The end of cycle life (EOL) 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 EOL 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

(continued)

BASES

BACKGROUND (continued)

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, 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. 3).

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 or RTP, loss of main feedwater flow, loss of load, rod ejection, 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, rod withdrawal at power, loss of load, and sudden decrease in feedwater temperature.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is at BOL or EOL. 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 BOL and EOL. An EOL measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOL value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(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 more positive than a given lower bound. The MTC is most positive at BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, all rods out (ARO), hot zero power conditions. At EOL 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 BOL and EOL 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. The BOL positive limit and the EOL 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.

BASES

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. 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 BOL 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. These withdrawal limits shall be in addition to the insertion limits required by LCO 3.1.7, “Control Bank Insertion Limits.”

As cycle burnup is increased, the RCS boron concentration 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.

(continued)

BASES

ACTIONS (continued)

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 3 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 EOL MTC limit means that the safety analysis assumptions for the EOL accidents that use a bounding negative MTC value may be invalid. If the EOL MTC limit is exceeded, 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 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 BOL 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 BOL 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 BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOL 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, a 300 ppm SR value of MTC should necessarily be less negative than the EOL LCO limit. The 300 ppm SR value is sufficiently less negative than the EOL LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

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

a. 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.

b. SR 3.1.3.2 is not required to be performed by measurement provided that the benchmark criteria in WCAP-13749-P-A (Ref. 4) are satisfied and the Revised Predicted MTC satisfies the 300 ppm surveillance limit specified in the COLR.

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

d. The Surveillance limit for RTP boron concentration of 100 ppm is conservative. If the measured MTC at 100 ppm is more positive than the 100 ppm Surveillance limit, the EOL 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.

(continued)

BASES

REFERENCES (continued)	3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.
	4. WCAP-13749-P-A, “Safety Evaluation Supporting the Conditional Exemption of the Most Negative EOL Moderator Temperature Coefficient Measurement, “ March 1997.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (e.g., 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 Protection" (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 control banks and 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

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BASES

BACKGROUND (continued)

of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and two shutdown banks. All control banks and shutdown banks contain two rod groups.

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 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 control 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 with a center to center distance of 3.75 inches, which is six steps. 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 with

(continued)

BASES

BACKGROUND (continued)

an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the normal indication accuracy of the DRPI System is ± 4 steps (all coils operable and 1 step added for manufacturing and temperature tolerances), and the maximum uncertainty is ± 10 steps (only one data system A or B coils operable). With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 22 steps.

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

b. The core remains subcritical after accident transients that result in a reactor trip, except for the MSLB.

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. 4). 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. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

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 directly by incore mapping. 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 10 CFR 50.36(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 also ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

The requirement to maintain the rod alignment to within plus or minus 12 steps 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.

(continued)

BASES

LCO (continued)

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 a self-sustaining chain reaction occurs, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are fully inserted and the reactor is shut down, with no self-sustaining chain reaction. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM), " for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are 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 emergency boration and restoring SDM.

In this situation, SDM verification must account for the absence of the negative reactivity of the untrippable rod(s), as well as a rod of maximum worth.

A.2

If the untrippable 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.

(continued)

BASES

ACTIONS

A.2 (continued)

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.1.1 and B.1.2

When a rod becomes misaligned, it can usually be moved and is still trippable.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the 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."

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 moved fully in and control bank C must be moved in to below 90 steps.

Power operation may continue with one RCCA 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.

(continued)

BASES

ACTIONS (continued)

B.2, B.3, B.4, and B.5

For continued operation with a misaligned rod, RTP 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. 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.

Verifying that $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, 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 flux maps of the core power distribution using the incore flux mapping system 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 accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

The following accident analyses are required to be reevaluated:

1. Rod Cluster Control Assembly Insertion Characteristics;

2. Rod Cluster Control Assembly Misalignment;

3. Loss Of Reactor Coolant From Small Ruptured Pipes or From Cracks In Large Pipes Which Actuates The Emergency Core Cooling System;

(continued)

ACTIONS

B.2, B.3, B.4, and B.5 (continued)

4. Single Rod Cluster Control Assembly Withdrawal At Full Power;
5. Major Reactor Coolant System Pipe Ruptures (Loss Of Coolant Accident);
6. Major Secondary System Pipe Rupture; and
7. Rupture Of A Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection).

C.1

When Required Actions 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 average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. 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 or 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 boric acid pumps. Boration will continue until the required SDM is restored.

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

(continued)

BASES

ACTIONS

D.2 (continued)

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that permits it to not be performed for rods associated with an inoperable demand position indicator or an inoperable rod position indicator. The alignment limit is based on the demand position indicator which is not available if the indicator is inoperable. LCO 3.1.7, “Rod Position Indication,” provides Actions to verify the rods are in alignment when one or more rod position indicators are inoperable.

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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

(continued)

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 ≥ 541°F to simulate a reactor trip under actual conditions.

Testing is performed with the rods fully withdrawn (225 to 231 steps inclusive). The fully withdrawn position used for determining rod drop times shall be greater than or equal to the fully withdrawn position used during subsequent plant operation.

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, Section 15.2.3.
4. FSAR, Section 15.2.3.2.2.C.

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 Protection," 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 control banks and 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. There are four control banks and two shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for individual 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 are normally automatically controlled by the Rod Control System, but they can also be manually controlled. 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.

(continued)

BASES

BACKGROUND (continued)

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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 that result in a reactor trip, except for the MSLB.

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 10 CFR 50.36(c)(2)(ii).

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.

The LCO is modified by a Note indicating the LCO requirement is not applicable to shutdown banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the shutdown bank to move below the LCO limits, which would normally violate the LCO. This Note applies to each shutdown bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins at 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

(continued)

BASES

APPLICABILITY (continued)

MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

ACTIONS

A.1, A.2.1, A.2.2, and A.3

If one shutdown bank is inserted less than or equal to 16 steps below the insertion limit, 24 hours is allowed to restore the shutdown bank to within the limit. This is necessary because the available SDM may be reduced with a shutdown bank not within its insertion limit. 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 a shutdown bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

While the shutdown bank is outside the insertion limit, all control banks must be within their insertion limits to ensure sufficient shutdown margin is available. The 24 hour Completion Time is sufficient to repair most rod control failures that would prevent movement of a shutdown bank.

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

When one or more shutdown banks is not within insertion limits (i.e., the entire bank is below the insertion limits) for reasons other than Condition A, 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. If one or more individual shutdown rods (but not an entire bank) is not within alignment limits (even if below the insertion limits), then LCO 3.1.4 should be entered and this Condition is not applicable.

(continued)

BASES

ACTIONS

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

C.1

If the Required Actions and associated Completion Times are not met, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

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 withdrawn before the control banks are withdrawn during a unit startup.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 Protection," 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 control banks and 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. There are four control banks and two shutdown banks. 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. An example is provided for information only in Figure B 3.1.6-1. The control banks are required to be at or above the insertion limit lines.

Figure B 3.1.6-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The predetermined position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, will be at 128 steps for a fully withdrawn position of 225 to 231 steps, inclusive. The fully withdrawn position is defined in the COLR.

(continued)

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. 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, “Rod Group Alignment,” LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, “Control Bank Insertion Limits,” LCO 3.2.3, "AXIAL FLUX DIFFERENCE (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:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 that result in a reactor trip, except for the MSLB.

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. 4).

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. 5).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36(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.

The LCO is modified by a Note indicating the LCO requirement is not applicable to control banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the control bank to move below the LCO limits, which would

(continued)

BASES

LCO (continued)

normally violate the LCO. This Note applies to each control bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.

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.

ACTIONS

A.1.1, A.2.1, A.2.2, and A.3

If Control Bank A, B, or C is inserted less than or equal to 16 steps below the insertion, sequence, or overlap limits, 24 hours is allowed to restore the control bank to within the limits. 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 a control bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

While the control bank is outside the insertion, sequence, or overlap limits, all shutdown banks must be within their insertion limits to ensure sufficient shutdown margin is available and that power distribution is controlled. The 24 hour Completion Time is sufficient to repair most rod control failures that would prevent movement of a shutdown bank.

Condition A is limited to Control banks A, B, or C. The allowance is not required for Control Bank D because the full power bank insertion limit can be met during performance of the SR 3.1.4.2 control rod freedom of movement (trippability) testing.

B1.1, B.1.2, B.2, C.1.1, C.1.2, and C.2

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

(continued)

BASES

ACTIONS

B1.1, B.1.2, B.2, C.1.1, C.1.2, and C.2 (continued)

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. 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 for reasons other than Condition A, they must be restored to meet the limits.

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 or evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

D.1

If the Required Actions 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1 (continued)

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP 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 ECP 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 ECP calculation with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.6.3

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, GDC 28.
2. 10 CFR 50.46,1988.
3. FSAR, Section 15.
4. FSAR, Section 4.3.2.6.
5. FSAR, Section 4.3.2.5.

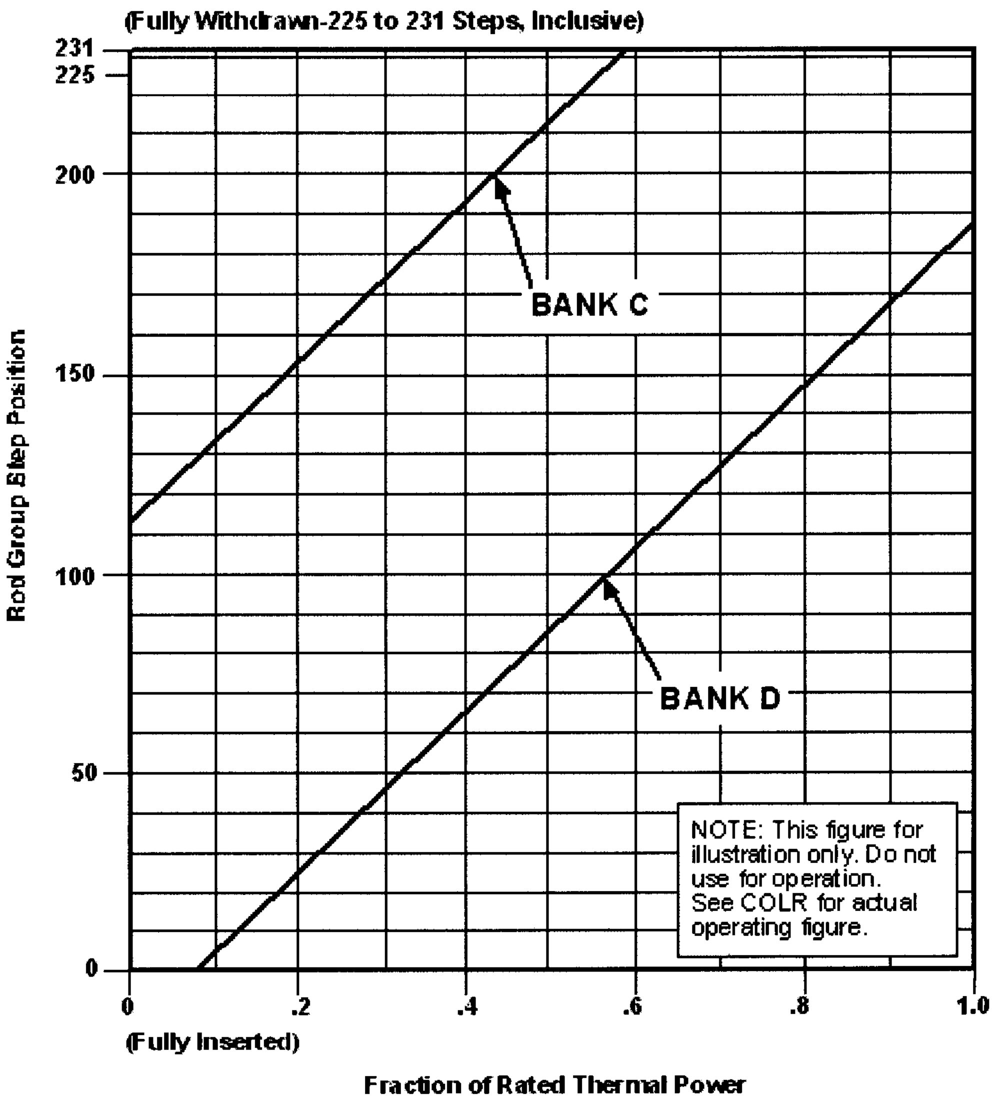

Figure 3.1.6-1
Rod Group Insertion Limits Versus Thermal Power

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 shutdown or 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.

(continued)

BACKGROUND (continued)

The axial positions 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 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 ± ? 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 control 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 with a center to center distance of 3.75 inches, which is 6 steps. 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 with an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the normal indication accuracy of the DRPI System is ± 4 steps (all coils operable and 1 step added for manufacturing and temperature tolerances), and the maximum uncertainty is ± 10 steps (only one data system A or B coils operable). With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 22 steps.

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 assumed 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 (Ref.2).

The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one DRPI System (data System A or B) and one Bank Demand Position Indication System be OPERABLE for each shutdown and control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The required DRPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits";

b. For the required DRPI System there are no failed coils; and

c. 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.

(continued)

BASES

LCO (continued)

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.

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

When one DRPI system (both A and B) per group fails in one or more groups, the position of the affected rod(s) may still be determined indirectly by use of the movable incore detectors. 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 non-indicating 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.

Required Action A.1 requires verification of the position of a rod with an inoperable DRPI once per 8 hours which may put excessive wear and tear on the movable incore detector system. Required Action A.2.1 provides an alternative. Required Action A.2.1 requires

(continued)

ACTIONS

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

verification of rod position using the movable incore detectors every 31 EFPD, which coincides with the normal use of the system to verify core power distribution.

Required Action A.2.1 includes six distinct requirements for verification of the position of rods associated with an inoperable DRPI using the movable incore detectors:

a. Initial verification within 8 hours of the inoperability of the DRPI;

b. Re-verification once every 31 Effective Full Power Days (EFPD) thereafter;

c. Verification within 8 hours if rod control system parameters indicate unintended rod movement. An unintended rod movement is defined as the release of the rod's stationary gripper when no action was demanded either manually or automatically from the rod control system, or a rod motion in a direction other than the direction demanded by the rod control system. Verifying that no unintended rod movement has occurred is performed by monitoring the rod control system stationary gripper coil current for indications of rod movement;

d. Verification within 8 hours if the rod with an inoperable DRPI is intentionally moved greater than 12 steps;

e. Verification prior to exceeding 50% RTP if power is reduced below 50% RTP; and

f. Verification within 8 hours of reaching 100% RTP if power is reduced to less than 100% RTP.

Should the rod with the inoperable DRPI be moved more than 12 steps, or if reactor power is changed, the position of the rod with the inoperable DRPI must be verified.

Required Action A.2.2 states that the inoperable DRPI must be restored to OPERABLE status prior to entering MODE 2 from MODE 3. The repair of the inoperable RPI must be performed prior to returning to power operation following a shutdown.

(continued)

ACTIONS (continued)

A.3

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

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 and B.2

When more than one DRPI channel per group in one or more groups fails (Data A and Data B), additional actions are necessary. Placing the Rod Control System in manual assures unplanned rod motion will not occur. 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.

The inoperable DRPIs must be restored, such that a maximum of one DRPI per group is inoperable, within 24 hours. 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.

Based on operating experience, normal plant 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.1.1, C.1.2, and C.2

With one DRPI inoperable in one or more groups and the affected groups have moved greater than 24 steps in one direction since the last determination of rod position, additional actions are needed to verify the position of rods within inoperable DRPI. Within 8 hours, the position of the rods with inoperable position indication must be determined using the movable incore detectors to verify these rods are still properly positioned, relative to their group positions.

If, within 8 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more

(continued)

ACTIONS

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

than 24 steps. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions using the movable incore detectors or reduce power to ≤ 50% RTP.

D.1.1 and D.1.2

With one or more demand position indicators per bank inoperable in one or more banks, 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 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.

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 specified in the COLR. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions D.1.1 and D.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 over the full indicated range ensures that the DRPI is operating correctly.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.7.1 (continued) The Surveillance is modified by a Note which states it is not required to be met for DRPIs associated with rods that do not meet LCO 3.1.4. If a rod is known to not be within 12 steps of the group demand position, the ACTIONS of LCO 3.1.4 provide the appropriate Actions.
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 (Ref. 4).

(continued)

BASES

BACKGROUND (continued)

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.

The PHYSICS TESTS required for reload fuel cycles (Ref. 4) in MODE 2 are listed below:

a. Critical Boron Concentration — Control Rods Withdrawn;

b. Critical Boron Concentration — Lead Bank Inserted;

c. Control Rod Worth; and

d. Isothermal Temperature Coefficient (ITC).

These tests are performed in MODE 2 at hot zero power (HZP), and they may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration — Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, the lead control bank is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test should not violate any of the referenced LCOs.

b. The Critical Boron Concentration — Control Rods Withdrawn except lead bank Test measures the critical boron concentration at HZP, with the lead bank fully inserted into the core. The reactivity resulting from each incremental bank movement is measured with a reactivity computer. The difference between the measured critical boron concentration with all rods fully withdrawn and with the lead bank inserted is determined. The boron reactivity coefficient is determined by dividing the measured bank worth by the measured boron concentration difference. Performance of this test could violate LCO 3.1.4, “Rod Group Alignment Limits”; LCO 3.1.5, “Shutdown Bank Insertion Limit”; or LCO 3.1.6, “Control Bank Insertion Limits.”

(continued)

BASES

BACKGROUND (continued)

c. The Control Rod Worth Test is used to measure the reactivity worth of shutdown and control banks. This test is performed at HZP and has four alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining shutdown and control banks. The second method, the Rod Swap Method, measures the worth of a predetermined lead or reference bank using the Boron Exchange Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted into the core. The worth of the selected bank is calculated, based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining shutdown and control banks. The third method, the Boron Endpoint Method, moves the selected bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the selected bank. This sequence is repeated for the remaining shutdown and control banks. The fourth method is based on measuring the reactivity worth of individual control and shutdown rod banks. It is a fast process that is accomplished by inserting and withdrawing the bank at a maximum stepping speed, without changing boron concentration, and recording the signals on the excore detectors. In this method, referred to as Dynamic Rod Worth Measurement technique, the recorded signals from the excore detectors are processed on a conventional reactivity meter, which solves the inverse point kinetics equation with proper analytical compensation for spacial effects. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

(continued)

BASES

BACKGROUND (continued)

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP and has two methods of performance. The first method, the Slope Method, varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The second method, the Endpoint Method, changes the RCS temperature and measures the reactivity at the beginning and end of the temperature change. The ITC is the total reactivity change divided by the total temperature change. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The Moderator Temperature Coefficient (MTC) at the beginning-of-life (BOL) is determined from the measured ITC. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

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 Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). 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 initial testing of the facility, including PHYSICS TESTS. Table 14.1-1 summarizes the zero, low power, and power tests. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1985 (Ref. 4). 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 ≥ 531°F, and SDM is within the limits provided 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 during PHYSICS TESTS meet Criteria 1, 2, and 3 of 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. One Power Range Neutron Flux Channel may be bypassed, reducing the number of required channels from 4 to 3. 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, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended and the number of required channels for LCO 3.3.1, “RTS Instrumentation,” Functions 2, 3, 6, and 17.e, may be reduced to 3 required channels during the performance of PHYSICS TESTS provided:

(continued)

BASES

LCO (continued)

a. THERMAL POWER is ≤ 5% RTP; and

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

c. RCS lowest loop average temperature is ≥ 531°F.

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 Immediately is adequate to ensure prompt operator action 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.

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 T_{avg} is < 531°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 531°F could violate the assumptions for accidents analyzed in the safety analyses.

(continued)

BASES

ACTIONS (continued)

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 loop T_{avg} is ≥ 531°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.4

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.4 (continued)

a. RCS boron concentration;

b. 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 relatively steady-state, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50.59.
3. Regulatory Guide 1.68, Revision 2, August, 1978.
4. ANSI/ANS-19.6.1-1985, December 13, 1985.
5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.
6. WCAP-11618, including Addendum 1, April 1989.
7. WCAP-13361-NP-A, “Westinghouse Dynamic Rod Worth Measurement Technique,” January 1996.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

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, "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 3.1.6, "Control Bank Insertion Limits," maintain the core within power distribution limits 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. These measurements are generally taken with the core at or near steady state 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 a steady state condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium 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 that accounts for the calculated worst case transient conditions.

Core monitoring and control under nonsteady 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.

BASES

APPLICABLE SAFETY ANALYSES

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

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

b. During normal operation, operational transients and any transient condition arising from events of moderate frequency, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the energy deposition to the fuel will be below 200 cal/gm, thus meeting the NRC acceptance criteria of $\leq$ 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).

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 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 10 CFR 50.36(c)(2)(ii).

BASES

LCO

To ensure that the Heat Flux Hot Channel Factor, $F_Q(Z)$, will remain within limits during steady state operation, $F_Q(Z)$ shall be limited by the following relationships which define the steady state limits:

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

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

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

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

For this facility, the actual values of F_Q^{RTP} and $K(Z)$ are given in the COLR.

An $F_Q(Z)$ 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 $F_Q(Z)$. Then, when using ≥ 38 detector thimbles:

$$F_Q(Z) = F_Q^M(Z) \text{ X } 1.0815$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances (3%) and flux map measurement uncertainty (5%), or

when using ≥ 25 and < 38 thimbles:

$$F_Q(Z) = F_Q^M(Z) \text{ X } 1.03 \text{ X } [1.05 + [2\{3 - (T/12.5)\}]/100],$$

where 1.03 accounts for fuel manufacturing tolerances with a more conservative flux map measurement uncertainty factor to account for fewer detector thimbles available, and T is the number of thimbles being used (Ref. 6). A bounding flux map measurement uncertainty of 7.0%, which is based on 25 thimbles, can be used for ≥ 25 and < 38 detector thimbles, if desired.

$F_Q(Z)$ evaluations for comparison to the steady state limits are applicable in all axial core regions, i.e., from 0 to 100% inclusive.

(continued)

BASES

LCO (continued)

Because flux maps are taken as a snap shot in steady state 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 ratio of the calculated transient $F_Q(Z)$ over the calculated steady state $F_Q(Z)$ as a function of core elevation, Z, is called W(Z).

The W(Z) curve is provided in the COLR for discrete core elevations. $F_Q(Z)$ evaluations for comparison to the transient limits are not following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 8% inclusive; and

b. Upper core region, from 92 to 100% inclusive.

The top and bottom 8% 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.

To account for power distribution transients encountered during normal operation, the transient limits for $F_Q(Z)$ are established utilizing the cycle dependent function W(Z). To ensure that $F_Q(Z)$ will not become excessively high if a normal operational transient occurs, $F_Q(Z)$ shall be limited by the following relationships which define the transient limits:

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

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

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. 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 $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

(continued)

BASES

LCO (continued)

Violating the LCO limits for $F_Q(Z)$ produces 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 $F_Q(Z)$ exceeds its steady state limit, maintains an acceptable absolute power density. $F_Q(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting 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.

A.2

A reduction of the Power Range Neutron Flux – High trip setpoints by ≥ 1% for each 1% by which $F_Q(Z)$ 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.

A.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q(Z)$ 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.

(continued)

BASES

ACTIONS (continued)

A.4

Verification that $F_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 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.

B.1

If it is found that $F_Q(Z)$ exceeds its specified transient limits, there exists a potential for $F_Q(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD by $\geq$ 1% for each 1% by which $F_Q(Z)$ exceeds its transient limits within the allowed Completion Time of 4 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factors are not exceeded (Ref.5). The percent $F_Q(Z)$ exceeds its transient limits is calculated based on the following expressions:

$$\left\{\left(\begin{array}{c}\text{maximum}\\\text{over } Z\end{array}\left[\frac{F_Q(Z) * W(Z)}{\frac{F_Q^{RTP}}{P} * K(Z)}\right]\right) - 1\right\} * 100 \quad \text{for } P > 0.5$$

$$\left\{\left(\begin{array}{c}\text{maximum}\\\text{over } Z\end{array}\left[\frac{F_Q(Z) * W(Z)}{\frac{F_Q^{RTP}}{0.5} * K(Z)}\right]\right) - 1\right\} * 100 \quad \text{for } P \leq 0.5$$

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during the first power ascension after a refueling. 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 $F_Q(Z)$ is within its specified limits after a power rise of more than 20% RTP over the THERMAL POWER at which it was last verified to be within specified limits. Because $F_Q(Z)$ could not have previously been measured in this 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 $F_Q(Z)$ is 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 $F_Q(Z)$ following a power increase of more than 20% ensures that $F_Q(Z)$ is 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 $F_Q(Z)$. 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 at least 20% higher than that power at which $F_Q(Z)$ was last measured.

SR 3.2.1.1

This surveillance is performed using the movable incore detectors to obtain a power distribution map at THERMAL POWER Levels greater than 5% RTP.

Verification that $F_Q(Z)$ is within its steady state limits involves increasing $F_Q^M(Z)$ by 3% to allow for manufacturing tolerance and by 5% to allow for measurement uncertainties in order to obtain $F_Q(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results. When using ≥ 38 detector thimbles, $F_Q(Z) = F_Q^M(Z) \times 1.0815$ (Ref. 4), and when using ≥ 25 and < 38 thimbles, $F_Q(Z) = F_Q^M(Z) \times 1.03 \times [1.05 + [2\{3 - (T/12.5)\}]/100]$, where T = the number of detector thimbles used (Ref. 6). A bounding flux map measurement uncertainty of 7.0%, which is based on 25 thimbles, can be used for ≥ 25 and < 38 detector thimbles, if desired. During initial

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

startup after a refueling outage up to and including performance of the first flux map at 100% RTP, ≥ 38 detector thimbles, with ≥ 2 detector thimbles per quadrant as identified in TRM Figure 13.3.1-1 are required. $F_Q(Z)$ is then compared to its steady state limits specified in the COLR and is applicable in all core plane regions, i.e., 0-100%, inclusive.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP following refueling ensures that the $F_Q(Z)$ 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 $F_Q(Z)$, another evaluation of this factor is required after achieving equilibrium conditions at this higher power level (to ensure that $F_Q(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.2.1.2

This surveillance is performed using the movable incore detectors to obtain a power distribution map at THERMAL POWER Levels greater than 5% RTP.

This surveillance determines if $F_Q(Z)$ will remain within its limit during a normal operational transient. If $F_Q(Z)$ is determined to exceed the transient limit, Action B.1 requires that the AFD limit be reduced 1% for each 1% $F_Q(Z)$ exceeds the transient limit. This will ensure that $F_Q(Z)$ will not exceed the transient limit during a normal operational transient within the reduced AFD limit.

When using ≥ 38 detector thimbles, $F_Q(Z) = F_Q^M(Z) \times 1.0815$ (Ref. 4), and when using ≥ 25 and < 38 thimbles, $F_Q(Z) = F_Q^M(Z) \times 1.03 \times$

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

[1.05 + [2{3 - (T/12.5)}]/100], where T = the number of detector thimbles used (Ref. 6). A bounding flux map measurement uncertainty of 7.0%, which is based on 25 thimbles, can be used for ≥ 25 and < 38 detector thimbles, if desired. During initial startup after a refueling outage up to and including performance of the first flux map at 100% RTP, ≥ 38 detector thimbles, with ≥ 2 detector thimbles per quadrant as identified in TRM Figure 13.3.1-1 are required.

For this surveillance, the $F_Q(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 8% inclusive; and

b. Upper core region, from 92 to 100% inclusive.

The top and bottom 8% 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.

Demonstrating that $F_Q(Z)$ is within the transient limit or reducing the AFD limit if the transient $F_Q(Z)$ limit was initially exceeded, only ensures that the transient $F_Q(Z)$ limit will not be exceeded at the time $F_Q(Z)$ was evaluated. This does not ensure that the limit will not be exceeded during the following surveillance interval. Both the steady state and transient $F_Q(Z)$ change as a function of core burnup.

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

$$\text{maximum over Z} \left[\frac{F_Q(Z)}{K(Z)} \right],$$

it is not guaranteed that $F_Q(Z)$ will remain within the transient limit during the following surveillance interval. SR 3.2.1.2 is modified by a Note to determine if there is sufficient margin to the transient $F_Q(Z)$ limit to ensure that the limit will not be exceeded during the following surveillance interval. This is accomplished by increasing $F_Q(Z)$ by the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

appropriate penalty factor specified in the COLR and comparing this value to the transient $F_Q(Z)$ limit. If there is insufficient margin, i.e., this value exceeds the limit, SR 3.2.1.2 must be repeated once per 7 EFPD until either $F_Q(Z)$ increased by the penalty factor is within the transient limit or, two successive (i.e., subsequent consecutive) flux maps indicate

$$\text{maximum over } Z \left[\frac{F_Q(Z)}{K(Z)} \right],$$

has not increased.

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

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.46, 1988.
2. FSAR, Section 15.4.6.
3. 10 CFR 50, Appendix A, GDC 26.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
5. WCAP-10216-P-A, Revision 1A, “Relaxation of Constant Axial Offset Control F_Q Surveillance Technical Specification,” February 1994.
6. FNP RER SNC799923-01, “Farley Unit 1 & 2 Movable Incore Detector System Thimble Reduction Study.”

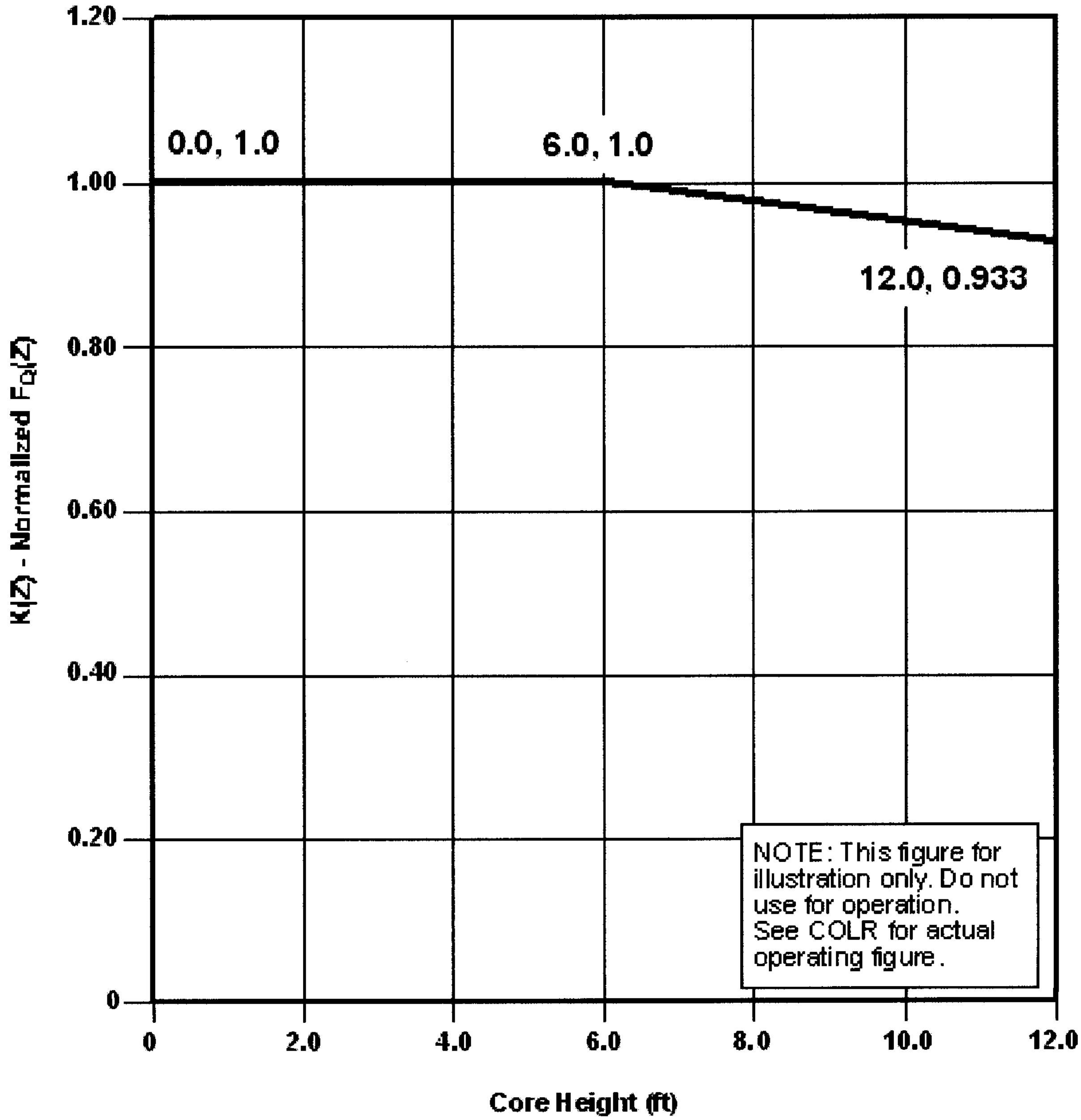

Figure B 3.2.1-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ as a Function of Core Height

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 fuel design limits at any location in the core during either normal operation or a postulated accident 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. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup except for a few months of reactor operation.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer 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.

The COLR provides peaking factor limits that ensure that the design criterion for 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.

(continued)

BASES

BACKGROUND (continued)

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is 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 $F_{\Delta H}^{N}$ preclude core power distributions that exceed the following fuel design limits:

a. 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 during normal operation, operational transients and any transient condition arising from events of moderate frequency;

b. During a loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F (Ref. 3);

c. During an ejected rod accident, the energy deposition to the fuel will be less than 200 cal/gm, thus meeting the NRC acceptance criteria of ≤ 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.

For transients that may be DNB limited, $F_{\Delta H}^{N}$ is an important core parameter. The limits on $F_{\Delta H}^{N}$ ensure that the DNB design criterion is met for normal operation, operational transients, and any transients arising from events of moderate frequency.

Minimum DNBR values (Ref. 4) were established that satisfy the DNB design criterion. These values provide the required degree of assurance that the hottest fuel rod in the core does not experience DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ 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 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 3.1.6, "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. Measurements are generally taken with the core at, or near, steady state 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 10 CFR 50.36(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 identifies 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.

(continued)

BASES

LCO (continued)

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 margin for higher radial peaking 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 0.3% for every 1% RTP reduction in THERMAL POWER.

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. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

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.

(continued)

BASES

ACTIONS

A.1.1 (continued)

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, if power is not reduced because $F^N_{\Delta H}$ is restored to within the limit within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, 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. 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 RTP 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. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

(continued)

BASES

ACTIONS (continued)

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.1 or A.1.2.1, an incore flux map (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 incore flux map, 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 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.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action. It is only applicable to the extent that THERMAL POWER has been reduced to comply with Required Actions A.1.1 or A.1.2.1. For example, if THERMAL POWER was only reduced to 70% RTP, then SR 3.2.2.1 must be performed prior to exceeding 75% RTP and within 24 hours after reaching 95% RTP.

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 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions.

Before making comparisons to the $F^N_{\Delta H}$ limit, the measured value of $F^N_{\Delta H}$ must be multiplied by a measurement uncertainty factor. When using ≥ 38 detector thimbles, the measured value of $F^N_{\Delta H}$ must be multiplied by 1.04. When using ≥ 25 and <38 thimbles, the measured value of $F^N_{\Delta H}$ must be multiplied by [1.04 + [2{3 - (T/12.5)}]/100], where T = the number of detector thimbles used (Ref. 5). A bounding flux map measurement uncertainty of 6.0%, which is based on 25 thimbles, can be used for ≥ 25 and < 38 detector thimbles, if desired. During initial startup after a refueling outage up to and including performance of the first flux map at 100% RTP, ≥ 38 detector thimbles, with ≥ 2 detector thimbles per quadrant as identified in TRM Figure 13.3.1-1 are required.

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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 15.4.6.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46, 1988.
4. FSAR, Section 4.4.1.
5. FNP RER SNC799923-01, “Farley Unit 1 & 2 Movable Incore Detector System Thimble Reduction Study.”

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of 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 loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The 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, Constant Axial Offset Control (CAOC), is used to control axial power distribution in day to day operation (Ref. 1). CAOC requires 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.

(continued)

BASES

BACKGROUND (continued)

RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

APPLICABLE SAFETY 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 temperature 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. 2) 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 LOCA and loss of flow 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 restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(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 the manual operation of the control banks or automatic motion of control banks.

(continued)

BASES

LCO (continued)

The automatic motion of the control banks is in response to temperature deviations resulting from 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. 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 detectors 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.

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RAOC AFD limits. 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 this LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its specified 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 of primary importance in safety analysis.

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.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.2.3.1</u> This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974. 2. R. W. Miller et al., "Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification," WCAP-10217-A, Rev. 1 (NP), February 1994.

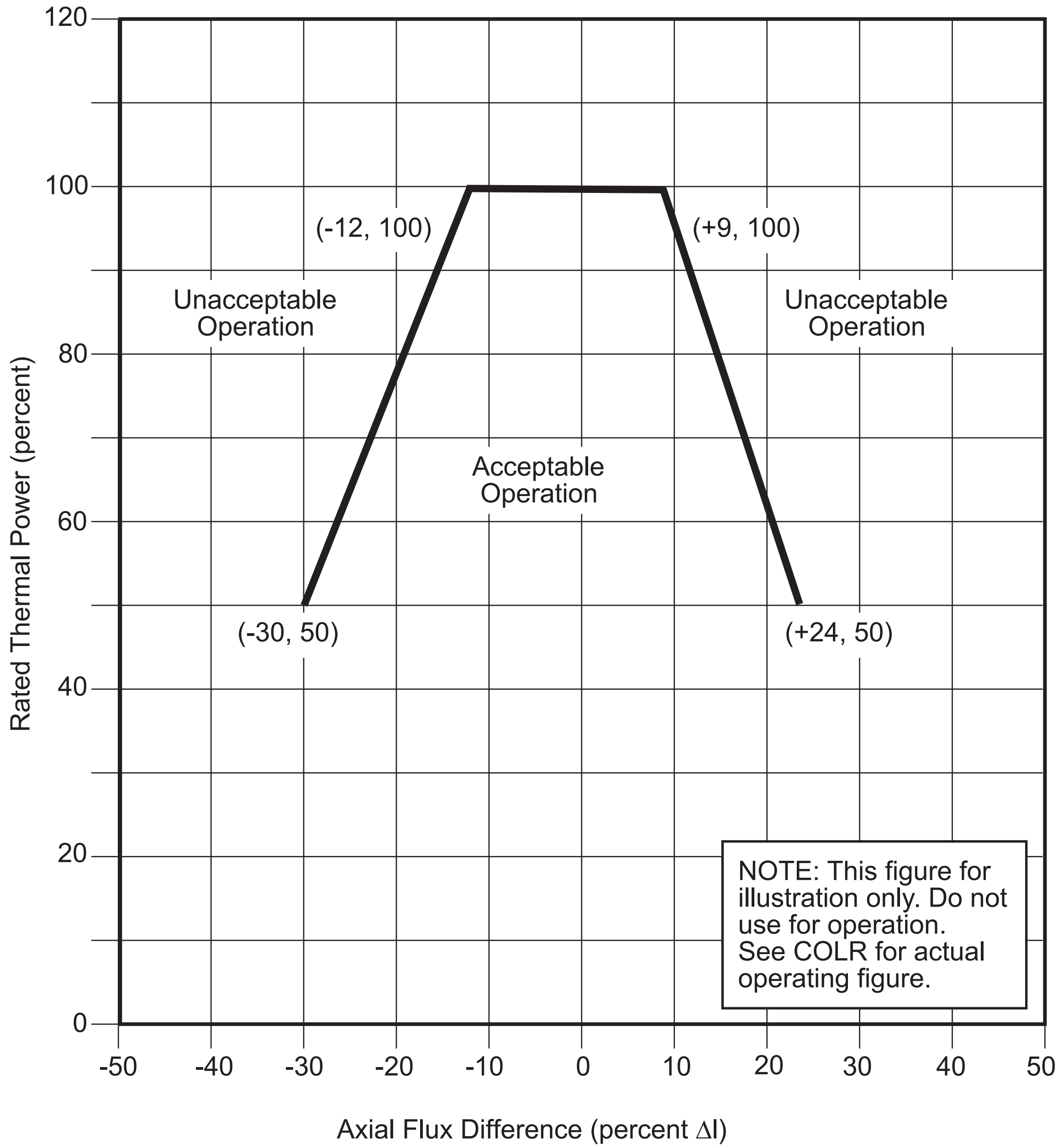

Figure B 3.2.3-1 (page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
as a Function of RATED THERMAL POWER

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 3.1.6, "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 loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During normal operation, operational transients and any transient condition arising from events of moderate frequency, 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 energy deposition to the fuel will be below 200 cal/gm, thus meeting the NRC acceptance criteria of $\leq$ 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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), 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 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 10 CFR 50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, at 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. The value of 1.02 was selected because the purpose of the LCO is to limit, or require detection of, gross changes in core power distribution between monthly incore flux maps. In addition, it is the lowest value of quadrant power tilt that can be used for an alarm without spurious actuation.

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.

BASES

ACTIONS

A.1

With the QPTR exceeding 1.02, limiting THERMAL POWER to ≥ 3% below 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 after each determination of QPTR 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 in Required Action A.2. Increases in QPTR would require a THERMAL POWER reduction within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable THERMAL POWER level. Conversely, 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 alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours. If the QPTR continues to increase, THERMAL POWER has to be reduced according to Required Action A.1. 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 $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, 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 required by 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 flux mapping. The above Completion Time of 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction required by Required Action A.1 takes into consideration the rate at which peaking factors are likely to

(continued)

BASES

ACTIONS

A.3 (continued)

change, and the time required to stabilize the plant and perform a flux map. 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 in ensuring that the power distribution remains consistent with the initial conditions used 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 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 re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses and will remain so after the return to RTP.

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 limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished by measuring currents for each detector during flux mapping and using this information to normalize the output from each detector (either through

(continued)

BASES

ACTIONS

A.5 (continued)

calibration of the NIS or through the use of constants in calculations) 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 QPTR is not restored to within limits until after the re-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 limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping 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 limits (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 at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, and $F^N_{\Delta H}$ are within their specified limits within 24 hours after achieving equilibrium conditions at RTP. Required Action A.6 also states that the peaking factor surveillance must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. This is an added precaution in the event that RTP is not achieved in a timely manner. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit 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 may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor

(continued)

BASES

ACTIONS

A.6 (continued)

surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. 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.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that the surveillance is only required to be performed if input to QPTR from one or more Power Range Neutron Flux channels is inoperable with THERMAL POWER >75% RTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. 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 power flux map can be used to generate power "tilt." This can be compared to a reference power tilt, from the most recent calibration flux map. Therefore, incore monitoring of QPTR can be used to confirm the accuracy of the QPTR as indicated by the excore detectors and that QPTR is within limits.

REFERENCES

1. 10 CFR 50.46, 1988.
2. FSAR, Section 15.4.6.
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.

Technical specifications are required by 10CFR50.36 to contain LSSS defined by the regulation as "…settings for automatic protective devices…so chosen that automatic protective action will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytic Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytic Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytic Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The Trip Setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytic Limit and thus ensuring that the SL would not be exceeded. As such, the Trip Setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the Trip Setpoint plays an important role in ensuring that SLs are not exceeded. As such, the Trip Setpoint meets the definition of an LSSS (Ref. 23) and could be used to meet the requirement that they be contained in the technical specifications.

(continued)

BASES

BACKGROUND (continued)

Technical specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. Operable is defined in technical specifications as "…being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as defined by 10 CFR 50.36 is the same as the OPERABILITY limit for these devices. However, use of the Trip Setpoint to define OPERABILITY in technical specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a surveillance. This would result in technical specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the Trip Setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the Trip Setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the Trip Setpoint to account for further drift during the next surveillance interval.

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

The Allowable Value specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the Trip Setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected

(continued)

BASES

BACKGROUND (continued)

during the surveillance interval. Note that, although the channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a technical specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

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

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

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

Operation within the SLs 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 50.67 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 illustrated in functional diagrams referenced in the FSAR, Chapter 7 (Ref. 1), and as identified below:

(continued)

BASES

BACKGROUND (continued)

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 Analog Protection 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;

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 in some cases as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument 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 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.

(continued)

BASES

BACKGROUND (continued)

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. These setpoints are discussed in FSAR, Chapter 7 (Ref. 1), Chapter 6 (Ref. 2), and Chapter 15 (Ref. 3) and specified in the FNP Unit 1(2) Precautions, Limitations, and Setpoints For Nuclear Steam Supply Systems (Ref. 4). 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. Otherwise, functional separation between the protection and control systems must be demonstrated as described in FSAR Section 7.2.2.3. In addition, 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. 5). The actual number of channels required for each unit parameter is specified in FSAR Table 7.2-1 (Ref. 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

(continued)

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

such that testing required while the reactor is at power may be accomplished without causing trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Allowable Values and RTS Setpoints

The trip setpoints used are based on the analytical limits stated in References 3 and 6. 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. 6), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Values and trip setpoints, including their explicit uncertainties, is provided in the RTS/ESFAS Setpoint Methodology Study (Ref. 7), which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each trip setpoint and corresponding Allowable Value. The trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value (LSSS) to account for measurement errors detectable by the 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.

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 surveillance interval selected 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 is therefore considered a “nominal” value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION.

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BASES

BACKGROUND

Allowable Values and RTS Setpoints (continued)

Trip setpoints consistent with the requirements of the Allowable Value ensure that SLs 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).

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 or superimposed on the field instrument signal. The process equipment for the channel in test is then tested, verified, and if required, calibrated. SRs for the channels are specified in the SRs section.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of inputs from field contacts and control board switches and 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. The reactor trip may be caused by a General Warning alarm in both trains or if both RTB bypass breakers BYA and BYB are racked in and closed. 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.

The SSPS performs the decision logic for actuating a reactor trip 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 input signals from field contacts, control board switches and 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

(continued)

BASES

BACKGROUND

Solid State Protection System (continued)

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

Two RTBs are connected in series in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of any one RTB 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 RTB 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 RTB bypass breakers are also equipped with a shunt trip device; however, manual actuation (local or remote) is required to energize this trip mechanism.

The decision logic matrix Functions are illustrated in the functional diagrams listed in Reference 10. In addition to the reactor trip or ESF, these diagrams also illustrate the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the selected 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.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the RTBs are closed.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 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 backups 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. 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 “as-left” calibration tolerance band of the Nominal Trip Setpoint. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions. Typically, failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of two, three, or four channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic 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 or functional separation between the protection and control systems must be demonstrated as described in FSAR Section 7.2.2.3. 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 random failure of one of the other three protection channels. Three operable instrumentation channels in a two-out-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 during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. The manual reactor trip feature is not credited by any safety analyses nor is it credited for diversity. 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 the shutdown rods or control rods are withdrawn or the Control Rod Drive (CRD) System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the CRD System is not capable of withdrawing the shutdown rods or control rods. If the rods cannot be withdrawn from the core, 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. NIS power range detector NI44 provides 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 control interlock 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, at most power levels, against a fast positive reactivity excursion leading to DNB and fuel overpower during power operations. These events 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. The channels are combined in a 2-out-of-4 trip Logic.

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 damage the fuel. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux — High does not have 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Power Range Neutron Flux—Low

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. The channels are combined in a 2-out-of-4 trip Logic.

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. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. Power Range Neutron Flux – High Positive Rate

The Power Range Neutron Flux – High Positive Rate trip uses the same NIS detectors 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 the accompanying ejection of the RCCA. In certain cases, this Function compliments the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Power Range Neutron Flux – High Positive Rate (continued)

Power Range Neutron Flux — High and Low Setpoint trip Functions to ensure that the criteria are met for reactivity excursions such as an inadvertent control rod withdrawal or a rod ejection event.

The LCO requires all four of the Power Range Neutron Flux — High Positive Rate channels to be OPERABLE. The channels are combined in a 2-out-of-4 trip Logic.

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 and administrative controls will provide protection against 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 diverse 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 channels also provide a control interlock 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. No credit is taken in the safety analyses for this trip function.

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. The trip function is accomplished by a 1-out-of-2 trip Logic.

Because this trip Function is important only during startup, there is generally no need to disable channels for on-line testing 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, 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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Intermediate Range Neutron Flux (continued)

withdrawal accident. 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.

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 diverse protection to the Power Range Neutron Flux — Low Setpoint trip Function. 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. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available. However, no credit is taken in the safety analyses for this trip function.

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 trip Function is accomplished by a 1-out-of-2 trip Logic. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open. In this case, the source range Function is to provide control room indication. The outputs of the Function to RTS logic are not required OPERABLE when the RTBs are open.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Source Range Neutron Flux (continued)

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides visual neutron flux indication in the control room.

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 Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range high Flux reactor trip is blocked and the detectors are manually de-energized.

In MODE 3, 4, or 5 with the reactor shut down, the Source Range Neutron Flux trip Function must also be OPERABLE. If the CRD 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 CRD System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.3, "Nuclear Instrumentation."

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT 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 when pressure is between the high and low pressure reactor trips. The core thermal power is correlated to the differential temperature across the vessel by measurement of Loop ΔT values at approximately full power with reactor coolant average temperature at the approximate cycle-specific full power reference temperature. The Overtemperature ΔT trip Function uses each

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average 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(ΔI), 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.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system and for RTD response time delays.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if the indicated ΔT equals or exceeds the calculated Overtemperature ΔT setpoint in two channels. Since the temperature signals are used for other control functions, 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. Control and Protection System interaction design requirements are addressed by implementation of T_{avg} and ΔT median selector circuits as discussed in FSAR Chapter 7.2. Note that this Function also provides a control interlock signal to prevent rod withdrawal prior to reaching the Trip Setpoint. Limiting further rod withdrawal may terminate the transient and prevent a reactor trip.

The LCO requires all three channels on the Overtemperature ΔT trip Function to be OPERABLE. The channels are combined in a 2-out-of-3 trip Logic. Note that the Overtemperature ΔT Function receives T_{avg}, ΔT, pressure, and upper and lower flux

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

inputs from channels shared with Overpower ΔT, pressurizer pressure, and NIS power range RTS/ESFAS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to ensure that the DNB design basis is met. 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.

7. Overpower ΔT

The Overpower ΔT trip Function provides protection for Condition I and II transients 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 ΔT trip Function and provides a backup to the Power Range Neutron Flux — High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. This trip function is explicitly credited in the safety analyses to mitigate the Consequences of small Steam Line breaks at full power. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature — the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and
- rate of change of reactor coolant average temperature — including dynamic compensation for the delays between the core and the temperature measurement system including RTD response time delays.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if the indicated ΔT equals or exceeds the calculated Overpower ΔT setpoint in two loops. Since the temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

protection function actuation and a single failure in the remaining channels providing the protection function actuation. Control and Protection System Interaction design requirements are addressed by implementation of T_{avg} and ΔT median selector circuits as discussed in FSAR Chapter 7.2. Note that these channels also provide a control interlock signal prior to reaching the Trip Setpoint which limits rod withdrawal. Limiting rod withdrawal may terminate the transient.

The LCO requires three channels of the Overpower ΔT trip Function to be OPERABLE. The channels are combined in a 2-out-of-3 trip Logic. Note that the Overpower ΔT trip Function receives T_{avg} and ΔT inputs from channels shared with the Overtemperature ΔT RTS Function. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT 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.

8. Pressurizer Pressure

The same transmitters provide input to the Pressurizer Pressure — High and — Low trips and the Overtemperature ΔT trip and the ESFAS (low pressure SI and P-11 interlock). A Dedicated Pressurizer Pressure control channel provides input to the Pressurizer Pressure Control System, therefore there are no control/protection interaction concerns. This trip Function is credited in several safety analyses.

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 Trip Setpoint limits the required range of

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Pressurizer Pressure — Low (continued)

protection provided by the Overtemperature ΔT trip Function. This trip is explicitly credited in the safety analyses to mitigate the consequences of a small break LOCA.

The LCO requires three channels of Pressurizer Pressure — Low to be OPERABLE. The channels are combined in a 2-out-of-3 trip Logic.

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% RTP or turbine power). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

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 safety valves to prevent RCS overpressure conditions. The high pressure trip setpoint Limits the required range of protection provided by the Overtemperature ΔT trip Function.

The LCO requires three channels of the Pressurizer Pressure — High to be OPERABLE. The channels are combined in a 2-out-of-3 trip Logic.

The Pressurizer Pressure — High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs and pressurizer spray valves.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Pressurizer Pressure — High (continued)

In MODE 1 or 2, the Pressurizer Pressure — High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the 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 below MODE 4.

9. Pressurizer Water Level — High

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 and power-operated relief valves (PORV). These valves are designed to pass steam in order to achieve their design energy removal rate, but are also qualified for limited water relief following specific transients. A reactor trip (Pressurizer Pressure — High) is actuated prior to the pressurizer becoming water solid. The Allowable value and Trip setpoint in Table 3.3.1-1 are specified in percent of instrument span. The LCO requires three channels of Pressurizer Water Level — High to be OPERABLE. The channels are combined in a 2-out-of-3 trip Logic. 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 because: (1) The pressurizer pressure high trip function is credited as the primary protection for RCS overpressure or pressurizer overfill events; (2) overfill transients resulting from postulated pressurizer level channel failures are sufficiently slow, such that the operator has adequate time to take corrective actions; and (3) the pressurizer pressure low trip function and ESFAS Functions are credited as the primary protection for RCS depressurization or pressurizer empty events.

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

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Pressurizer Water Level — High (continued)

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.

10. Reactor Coolant Flow — Low

The Allowable Value and Trip Setpoint for this function in Table 3.3.1-1 are specified in percent of indicated flow. The indicated flow is normalized based on the measured ΔP at 100% RTP (Ref. 1).

The Reactor Coolant Flow — Low (Single Loop) trip Function provides primary protection for all loss of flow events. For DNB limiting events, including complete loss of flow, this trip 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. This trip Function also mitigates the consequences of an RCP locked rotor event by ensuring that the RCS pressure limit is not exceeded and that the core geometry remains amenable to cooling. Above the P-8 setpoint, which is approximately 30% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow — Low channels per loop to be OPERABLE in MODE 1 above P-8. The trip function is accomplished by 2-out-of-3 channels in a single Loop.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in violating the DNB design basis. In MODE 1 below the P-8 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

10. Reactor Coolant Flow — Low (continued)

The Reactor Coolant Flow — Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors (shared with the Single Loop trip Function) to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow — Low channels per loop to be OPERABLE. The trip function is accomplished by 2-out-of-3 channels in two Loops.

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. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. 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 one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

11. Not used.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 on each RCP bus is monitored by undervoltage relays. Two UV sensors (relays) are associated with each bus (one for each logic train). The UV sensors (relays) are associated with the motor side of the RCP breakers. Each RCP bus is assigned to a protection channel. The actuation logic is two-out-of-three channels (i.e., buses) with loss of voltage. The RCP UV reactor trip logic is interlocked by permissive P-7. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. For undervoltage conditions on multiple RCP buses, this trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Two Loops) Trip Setpoint is reached. A minimum time delay is incorporated into each Undervoltage RCP channel to prevent reactor trips due to momentary electrical power transients (e.g., fault clearing and fast bus transfer). This time delay is also set so that the time required for a signal to reach the RTBs following the simultaneous loss of power of two or more RCP buses shall not exceed the maximum allotted for protection system equipment (Ref. 18). An additional time delay is allotted for EMF decay.

This is an anticipatory trip for reactor core protection against violating the DNB design basis. The primary trip is provided by the loss of flow trip. No credit was taken in the accident analyses for the function of this trip. However, the functional capability of this trip enhances the overall reliability of the reactor protection system.

The LCO requires three Undervoltage channels to be OPERABLE.

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 no conceivable power distributions could occur that would challenge the DNB design basis at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. This Function uses the same undervoltage channels and Logic circuits as the ESFAS Function 6.d, "Undervoltage Reactor Coolant Pump (RCP)" start of the Turbine-Driven auxiliary feedwater (TDAFW) pump. However, the TDAFW actuation does not employ the P-7 interlock.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Two UF sensors (relays) are associated with each bus (one for each logic train). Each RCP bus is assigned to a protection channel. The actuation logic is two-out-of-three channels (i.e., buses) with an underfrequency condition. The RCP UF reactor trip logic is interlocked by permissive P-7. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a reactor trip and open the RCP breaker to preclude any reduction in the coast down of the RCPs. This trip Function will generate a reactor trip before the Reactor Coolant Flow — Low (Two Loops) Trip Setpoint is reached. This is an anticipatory trip for reactor core protection against violating the DNB design basis. The primary trip is provided by the loss of flow trip. No credit was taken in the accident analyses for the function of this trip. However, the functional capability of this trip enhances the overall reliability of the reactor protection system. A minimum time delay is incorporated into each Underfrequency RCP channel to prevent reactor trips due to momentary electrical power transients (e.g., fault clearing and fast bus transfer). This time delay is also set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip setpoint is reached shall not exceed the maximum allotted for protection system equipment (Ref. 18).

The LCO requires three Underfrequency channels to be OPERABLE.

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 no conceivable power distributions could occur that would challenge the DNB design basis at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. This function also trips the RCP Breakers open to prevent excessive RCP speed reduction. This feature is not interlocked with P-7, and it is not credited in the safety analysis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 level in any SG is indicative of a loss of heat sink for the reactor. The Allowable Value and Trip Setpoint for this function in Table 3.3.1-1 are specified in percent of narrow range instrument span in each SG. 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. Section 2.12.5 (Ref. 10) and Section 7.2.2.2.1E (Ref. 1) discuss the control and protection system interaction for this function which is provided by median signal selection. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level — Low Low per SG to be OPERABLE. The trip Function is accomplished by actuation of two channels on any SG.

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. 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, 4, 5, or 6, the SG Water Level — Low Low 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

15. Turbine Trip

a. Turbine Trip — Low Auto Stop Oil Pressure

The Turbine Trip — Low Auto Stop 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 and the Reactor Coolant System Pressure Boundary components. Any turbine trip from a power level below the P-9 setpoint, approximately 50% power, will not actuate a reactor trip. Three pressure switches monitor the turbine control oil system pressure. 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 and RCS integrity are provided by the Pressurizer Pressure — High and Overtemperature ΔT trip Functions and by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip — Low Auto Stop Oil Pressure to be OPERABLE in MODE 1 above P-9. The channels are combined in a 2-out-of-3 trip Logic.

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 Auto Stop Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip — Turbine Throttle Valve Closure

The Turbine Trip — Turbine Throttle Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-9 setpoint, approximately 50% power. Below the P-9 setpoint this action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the throttle valves close. Tripping the reactor in anticipation of loss of secondary heat removal

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Turbine Trip — Turbine Throttle Valve Closure (continued)

acts to minimize the pressure and temperature transient on the reactor and the Reactor Coolant System Pressure Boundary components. 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 and RCS integrity are provided by the Pressurizer Pressure — High and Overtemperature ΔT trip Functions, and by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip — Low Auto Stop Oil Pressure trip Function. Each turbine throttle valve is equipped with one limit switch that inputs to the RTS logic trains. If all four limit switches indicate that the throttle valves are all closed, a reactor trip is initiated.

There is no safety analysis limit and there is no LSSS for this Function. The calibration requirement is to set the limit switch to assure channel trip occurs when the associated throttle valve is completely closed.

The LCO requires four Turbine Trip — Turbine Throttle 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 System in conjunction with the Auto Rod Control System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip — Throttle Valve Closure trip Function does not need to be OPERABLE.

16. 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 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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

16. Safety Injection Input from Engineered Safety Feature Actuation System (continued)

the most reactive 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 relay in 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 to shut down the reactor in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

17. 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:

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 (continued)

- 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; and

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

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 to ensure the Source Range Reactor Trip logic is enabled.

Above the P-6 interlock setpoint, this Function is not required for safety.

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. Low Power Reactor Trips Block, P-7

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 Impulse 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 (Two Loops);

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b. Low Power Reactor Trips Block, P-7 (continued)

- Undervoltage RCPs; and
- Underfrequency RCPs.

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 (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

Trip Setpoint and Allowable Value 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.

Since the P-7 interlock has no channels, no CHANNEL CALIBRATION or CHANNEL OPERABILITY TEST is needed. The logic is tested by SR 3.3.1.5 under Function 20, Automatic Trip Logic.

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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 30% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow — Low (Single Loop) reactor trip on 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 challenge the DNB design basis when greater than approximately 30% 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 challenge the DNB design basis.

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 Auto Stop Oil Pressure and Turbine Trip — Turbine Throttle 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 capacity of the Steam Dump System in conjunction with the Auto Rod Control System. 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 and the Reactor Coolant System Pressure Boundary components.

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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-9 (continued)

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System in conjunction with the auto rod control system, 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 capacity of the Steam Dump System in conjunction with the auto rod control system.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Power Range Neutron Flux, P-10 (continued)

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 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. Turbine Impulse Pressure, P-13

The Turbine Impulse 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 rated full load pressure. The Trip Setpoint and Allowable Value for this function in Table 3.3.1-1 are specified in percent Turbine power which is based on the impluse pressure equivalent. This 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 Impulse Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine Impulse Chamber 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 reactor trips enabled by P-7 are not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO and APPLICABILITY (continued)

18. 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. 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 RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

19. 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 CRD System, or declared inoperable under Function 18 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 RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

20. Automatic Trip Logic (continued)

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE trains ensures that random failure of a single logic train 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 or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

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

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 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 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 Condition B is no longer applicable. 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 is 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 applies to this trip Function.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal:

- 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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, the RTBs must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, 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.

D.1 and D.2

Condition D applies to the Power Range Neutron Flux — High and Power Range Neutron Flux – High Positive Rate Functions.

The NIS has 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).

The Required Actions have been modified by two Notes. Note 1 allows a channel to be placed in the bypassed condition for up to 12 hours while performing routine surveillance testing. With one channel inoperable, the Note also allows routine surveillance testing of another channel with a channel in bypass. The Note also allows placing a channel in the bypass condition to allow setpoint adjustments when required to reduce the Power Range Neutron Flux-High setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 11.

Note 2 refers the user to LCO 3.2.4 for additional requirements that may apply for an inoperable power range channel.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

As an alternative to the above Action, 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 an additional 6 hours for the MODE reduction beyond the Completion Time for Required Action D.1. 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.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux — Low;
- Overtemperature ΔT;
- Overpower ΔT;
- 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 inoperable 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 the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 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, 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 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. However, this does not preclude actions to maintain or increase RCS inventory or place the unit in a safe conservative condition provided the required SDM is maintained. The suspension of positive reactivity additions 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. 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.

H.1

Condition H applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels are inoperable. Below the P-6 setpoint, the NIS source range performs a monitoring and protection function redundant to the credited Power Range Low Trip Function. The inoperable NIS intermediate range channel(s) must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. The NIS intermediate range 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.

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs a monitoring and protection function redundant to the credited Power Range Low Trip Function. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power

(continued)

BASES

ACTIONS

I.1 (continued)

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. However, this does not preclude actions to maintain or increase RCS inventory or place the unit in a safe conservative condition provided the required SDM is maintained.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and performing a reactor startup, or in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs a monitoring and protection function redundant to the credited Power Range Low Trip Function. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition and the unit enters Condition L.

K.1 and K.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs a monitoring and protection function redundant to the credited Power Range Low Trip Function. 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, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit enters Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 12.

(continued)

BASES

ACTIONS (continued)

L.1, L.2, and L.3

Condition L applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs a monitoring function. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. However, this does not preclude actions to maintain or increase RCS inventory or place the unit in a safe conservative condition provided the required SDM is maintained. In addition to suspension of positive reactivity additions, all valves that could add unborated water to the RCS must be closed within 1 hour. The isolation of unborated water sources will preclude a boron dilution accident.

Also, the SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM within 1 hour allows sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

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 (Single Loop);
- Reactor Coolant Flow — Low (Two Loop);

(continued)

BASES

ACTIONS

M.1 and M.2 (continued)

- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. For RCP UV and RCP UF, both sensors associated with a given channel must be tripped (or, if applicable, bypassed) to satisfy the requirements of action M.1. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint (above P-8 for Reactor Coolant Flow — Low (Single Loop)). These Functions do not have to be OPERABLE below the P-7 setpoint because the trip protection provided is no longer required. 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. The Reactor Coolant Flow — Low (Single Loop) reactor trip Function does not have to be OPERABLE below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint if an inoperable channel is not tripped within 72 hours due to shared components between this Function and the Reactor Coolant Flow — Low (Two Loops) trip function.

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 have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 11.

(Unit 2 only) N.1 and N.2

Condition N applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position channel per RCP breaker. Each channel contains one Train A and one Train B auxiliary contact. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must

(continued)

BASES

ACTIONS

N.1 and N.2 (continued)

Not used.

O.1 and O.2

Not used.

P.1 and P.2

Condition P applies to Turbine Trip on Low Auto Stop Oil Pressure. With one channel inoperable, the inoperable channel must be placed in

(continued)

BASES

ACTIONS

P.1 and P.2 (continued)

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 is justified in Reference 11. The additional 4 hours for reducing power is reasonable based on operating experience.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 11.

Q.1 and Q.2

Condition Q applies to the Turbine Trip on Throttle Valve Closure Function. With one, two, or three channels inoperable, each inoperable channel must be placed in the trip condition within 72 hours. Since all the valves must be tripped in order for the reactor trip signal to be generated, it is acceptable to place more than one Turbine Throttle Valve Closure channel in the tripped condition. If a 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 each inoperable channel in the tripped condition is justified in Reference 11. The additional 4 hours for reducing power is reasonable based on operating experience.

R.1 and R.2

Condition R 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 R.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action R.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 RTS Automatic Trip Logic train to OPERABLE status is justified in Reference 11. The Completion Time of 6 hours (Required Action R.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and

(continued)

BASES

ACTIONS

R.1 and R.2 (continued)

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. The 4 hour time limit for testing the RTS Automatic Trip Logic train may include testing the RTB also, if both the Logic test and RTB test are conducted within the 4 hour time limit. The 4 hour time limit is justified in Reference 11.

S.1 and S.2

Condition S 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 is 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 15. 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 removes the requirement for this particular Function.

The Required Actions have been modified by a Note. The Note allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4 hour time limit is justified in Reference 15.

T.1 and T.2

Condition T applies to the P-6 and P-10 interlocks. This Condition is applicable when the interlock is inoperable to the extent that a reactor trip which should not be blocked in the current MODE is blocked. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, 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 accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the

(continued)

BASES

ACTIONS

T.1 and T.2 (continued)

minimum amount of time allowed for 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.

U.1 and U.2

Condition U applies to the P-7, P-8, P-9, and P-13 interlocks. This Condition is applicable when the interlock is inoperable to the extent that a reactor trip which should not be blocked in the current MODE is blocked. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, 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 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.

V.1 and V.2

Condition V 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 Condition V is no longer applicable. 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 applies to this trip Function. 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.

With the unit in MODE 3, Condition C applies to this trip Function. The Required Actions have been modified by a Note. The Note allows one

(continued)

BASES

ACTIONS

V.1 and V.2 (continued)

RTB to be bypassed for maintenance on an undervoltage or shunt trip mechanism if the other RTB train is OPERABLE. However, the affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance on one of the diverse features. While no explicit bypass time duration is provided by this Note, it is expected that such corrective maintenance would be accomplished in a timely manner. Reference 13 provides the basis for the bypass allowance.

The 48 hour Completion Time is based on confirmation of the OPERABILITY of the other diverse trip mechanism and the associated RTB during the test which identifies a failure of one diverse trip feature (Ref. 13).

The Completion Time of 48 hours for Required Action V.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.

W.1

With two RTS trains inoperable, no automatic capability is available to shut down the reactor, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1

Performance of the CHANNEL CHECK 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 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.

A Note modifies SR 3.3.1.1. The Note provides a clarification that the source range instrumentation surveillance is only required when reactor power is < P-6 and that 1 hour after power is reduced below P-6 is allowed for performing the surveillance for this instrumentation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the power range channel output every 24 hours. If the calorimetric heat balance calculation results exceed the power range channel indicated power by more than + 2% RTP, the power range channel is not declared inoperable, but must be adjusted. The power range channel output shall be adjusted consistent with the calorimetric heat balance calculation results if the calorimetric calculation exceeds the power range channel output by more than + 2% RTP. If the power range channel output cannot be properly adjusted, the channel is declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

If the calorimetric is performed at part power (< 50% RTP), adjusting the power range channel indication in the increasing power direction will assure a reactor trip below the safety analysis limit (≤ 118% RTP). Making no adjustment to the power range channel indication in the decreasing power direction due to a part power calorimetric assures a reactor trip consistent with the safety analyses. This allowance does not preclude making indicated power adjustments, if desired, when the calorimetric heat balance calculation is less than the power range channel indicated power. To provide close agreement between indicated power and calorimetric power and to preserve operating margin, the power range channels are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the power range channel indicated power is adjusted in the decreasing power direction due to a part power calorimetric (< 50% RTP). This action could introduce a non-conservative bias at higher power levels which could result in a power range reactor trip above the safety analysis limit (> 118% RTP). The cause of the potential non-conservative bias is the decreased accuracy of the calorimetric at reduced power conditions. The primary error contributor to the instrument uncertainty for a secondary side power calorimetric measurement is the feedwater flow measurement, which is typically a ΔP measurement across a 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 even though the ΔP error has not changed. An evaluation of extended operation at part power conditions would conclude that it is prudent to administratively adjust the setpoint of the Power Range Neutron Flux - High bistables to ≤ 85% RTP when: 1) the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric below 50% RTP; or 2) for a post refueling startup. The evaluation of extended operation at part power conditions would also 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 ≤ 109% RTP, the NIS channel calibration must be confirmed based on a calorimetric performed ≥ 50% RTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

SR 3.3.1.2 is modified by a Note. This 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., automatic rod control capability and turbine generator synchronized to the grid.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output. If the absolute difference is ≥ 3% RTP the NIS channel is still OPERABLE, but it must be adjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3% RTP.

If the NIS channel cannot be properly adjusted, the channel is declared inoperable. This Surveillance is performed to periodically verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 clarifies that the Surveillance is required only if reactor power is ≥ 50% RTP and that 7 days are allowed for performing the Surveillance and channel adjustment, if necessary, after reaching 50% RTP. A power level of ≥ 50% RTP is consistent with the requirements of SR 3.3.1.9. Note 2 allows SR 3.3.1.9 to be performed in lieu of SR 3.3.1.3, since SR 3.3.1.9 calibrates (i.e., requires channel adjustment) the excore channels to the incore channels, it envelopes the performance of SR 3.3.1.3.

For each operating cycle, the initial channel normalization is performed under SR 3.3.1.9. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage trip via the Reactor Protection System and the local manual shunt trip

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

mechanism. The bypass breaker test shall include a local manual shunt trip and local manual undervoltage trip. A Note has been added to indicate that this test must be performed on a bypass breaker prior to placing it in service. The independent test of undervoltage and shunt trip circuitry for the bypass breakers for the manual reactor trip function is included in SR 3.3.1.12. No capability is provided for performing such a test at power.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested 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 and permissive function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.6

SR 3.3.1.6 is the performance of a TADOT. The function is tested up to the SSPS logic circuit. Setpoints must be found within the Allowable Values specified in Table 3.3.1-1.

The test includes the undervoltage and underfrequency sensing devices that provide actuation signals directly to the SSPS. The test functionally demonstrates channel OPERABILITY including verification of the trip setpoint. If necessary, the undervoltage/underfrequency setpoint is restored to within calibration tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT.

A COT is performed on each required channel to ensure the rack components will perform the intended Function.

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The "as found" and "as left" data have been evaluated to ensure consistency with (i.e., bounded by) the drift allowance used in the setpoint methodology. The COT "as found" limits are based, in part, on expected performance of a healthy instrument channel. Appropriate corrective action is taken when the "as found" values exceed the prescribed values. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

SR 3.3.1.7 is modified by a Note that 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within the Frequency specified in the Surveillance Frequency Control Program of the Frequencies prior to reactor startup and four hours after reducing power below P-10 and P-6. 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 below P-10" (applicable to the intermediate range and the 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

Frequency specified in the Surveillance Frequency Control Program applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and twelve and four hours after reducing power below P-10 or P-6, respectively. 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 time limit. Twelve hours and four hours are reasonable times 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 periods > 12 and 4 hours, respectively. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.9

SR 3.3.1.9 is a calibration of the excore channels to the incore channels based on analysis of a range of core flux distributions or a single core flux distribution coupled with core design information. If the measurements do not agree, the excore channels are not declared inoperable but must be adjusted (i.e., normalized) to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed at BOL to normalize the excore f(ΔI) input to the overtemperature ΔT Function for a given operating cycle. The surveillance also normalizes the excore ΔI indications.

Two Notes modify SR 3.3.1.9. Note 1 states that neutron detectors are excluded from the calibration. Note 2 specifies that this Surveillance is required only if reactor power is ≥ 50% RTP and that 7 days are allowed for completing the surveillance after reaching 50% RTP. Based on operating experience, a time allowance of 7 days for test performance, data analysis, and channel adjustments is sufficient. A power level of ≥ 50% RTP corresponds to the power level for the AFD surveillance (SR 3.2.3.1), which requires calibrated excore ΔI indications.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.9 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.10

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.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The "as found" and “as left” data have been evaluated to ensure consistency with (i.e., bounded by) the drift allowance used in the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 states that neutron detectors are excluded from the CHANNEL CALIBRATION where applicable. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detector outputs based on an incore/excore cross-calibration (SR 3.3.1.9). In addition, the CHANNEL CALIBRATION for the power range neutron detector outputs includes normalization of the channel output based on a power calorimetric (SR 3.3.1.2) performed above 15% RTP. The CHANNEL CALIBRATION for the intermediate range neutron detector outputs includes normalization of the high flux bistable based on a power calorimetric. The CHANNEL CALIBRATION for the source range neutron detectors consists of obtaining new detector plateau and preamp discriminator curves after a detector is replaced. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. Note 2 states that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. The OTΔT, OPΔT, and the power range neutron flux rate functions contain required time constants.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.11

SR 3.3.1.11 is the performance of a COT of RTS interlocks. This COT is also intended to verify the interlock prior to startup, if not performed in the Frequency specified in the Surveillance Frequency Control Program.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Performance of the RTS Interlock COTs in conjunction with periodic actuation logic tests (SR 3.3.1.5) provides assurance that the total interlock function is OPERABLE prior to reactor startup and power ascension.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a TADOT of the Manual Reactor Trip and the SI Input from ESFAS. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

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 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of Turbine Trip Functions prior to exceeding P-9. This TADOT consists of verifying that each channel indicates a Turbine trip before Latching the turbine and indicates no turbine trip after the turbine is latched prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. A Note states that this Surveillance is not required if it has been performed within the

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.13 (continued)

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. This test may be performed with the reactor at power below P-9 and/or prior to reactor startup.

SR 3.3.1.14

SR 3.3.1.14 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in FSAR, Table 7.2.5 (Ref. 16). Individual component response times are not typically 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 when the rods are free to fall (i.e., control and shutdown loss of control rod drive mechanism (CRDM) stationary gripper voltage, including gripper release delay time (Ref. 17)).

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 set to one, or with the time constants set to their nominal value. The test results must be compared to properly defined acceptance criteria.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel in any series of sequential or overlapping measurements. Allocations for specific pressure and differential pressure sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications.

WCAP – 13632-P-A, Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” (Ref. 18) provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," (Ref. 19) provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for the sensor, signal conditioning and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electric repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where time response could be affected is replacing the sensing assembly of a transmitter.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.14 is modified by a Note stating that neutron 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.

REFERENCES

1. FSAR, Chapter 7.

2. FSAR, Chapter 6.

3. FSAR, Chapter 15.

4. Joseph M. Farley Nuclear Power Plant Unit 1 (2) Precautions, Limitations and Setpoints U–266647 (U–280912).

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BASES

REFERENCES (continued)

5. IEEE-279-1971

6. 10 CFR 50.49.

7. WCAP 13751, Rev. 1, Westinghouse Setpoint Methodology for Protection Systems Farley Nuclear Plant Units 1 and 2.

8. WCAP 13751 Rev. 0, Westinghouse Setpoint Methodology for Protection Systems SNOC Farley Nuclear Plant Units 1 and 2.

9. Joseph M. Farley Nuclear Power Plant Units 1 & 2 Precautions, Limitations, and Setpoints for Nuclear Steam Supply Systems, March 1978, U258631/U278997 Rev. 5.

10. Alabama Power Company Joseph M. Farley Units 1 and 2 Functional Diagrams Westinghouse Drawing 5655D37, Sheets 1-8.

11. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

12. WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report as approved by the NRC and documented in the SERs and SSER (letters to J.J. Sheppard from Cecil O. Thomas dated February 21, 1985; Roger A. Newton from Charles E. Rossi dated February 22, 1989; and Gerard T. Goering from Charles E. Rossi dated April 30, 1990).

13. NRC Generic Letter 85-09, "Technical Specifications For Generic Letter 83-28 [Required Actions Based On Generic Implications Of Salem ATWS Events], Item 43."

14. Westinghouse Technical Bulletin, ESBU-TB-92-14-R1, "Decalibration Effects of Calorimetric Power Level Measurements On The NIS High Power Reactor Trip At Power Levels Less Than 70% RTP."

15. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

16. FSAR, Table 7.2.5.

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BASES

REFERENCES (continued)

17. Westinghouse Technical Bulletin, NSD-TB-92-03-R1, "Undervoltage Trip Protection."

18. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," Jan., 1996.

19. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," Oct., 1998.

20. WCAP 12925, Median Signal Selector (MSS).

21. WCAP 13807/13808, Elimination of Feedwater Flow trip via Implementation of MSS.

22. SNC Calculation E-35.1A & E-35.2A.

23. Regulatory Guide 1.105, Revision 3, “Setpoints for Safety-Related Instrumentation.”

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 analog protection 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 establish 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 a channel is “OPERABLE” under these circumstances, the ESFAS setpoint must be left adjusted to 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 statistical 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 in some cases 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. The OPERABILITY of each transmitter or sensor 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. These setpoints are discussed in FSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3) and specified in the FNP Unit 1 (2) Precautions, Limitations, and setpoints for Nuclear Steam Supply systems (Ref. 4). 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.

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BASES

BACKGROUND (continued)

Signal Processing Equipment (continued)

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. Otherwise, functional separation between the protection and control systems must be demonstrated as described in FSAR Chapter 7.2.2.2. In addition, 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. 5). The actual number of channels required for each unit parameter is specified in Reference 2.

Allowable Values and ESFAS Setpoints

The trip setpoints used are based on the analytical limits stated in References 3 and 6. 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. 7), the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservative with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Value and ESFAS setpoints including their explicit uncertainties, is provided in the plant specific setpoint methodology study (Ref. 6) which incorporates all of the known uncertainties applicable to each channel. The magnitudes of these uncertainties are factored into the determination of each ESFAS setpoint and corresponding Allowable Value. The nominal ESFAS setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for measurement errors detectable by the 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.

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BASES

BACKGROUND

Allowable Values and ESFAS Setpoints (continued)

The ESFAS setpoints are the values at which the bistables are set and is the expected value to be achieved during calibration. The ESFAS setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the “as-left” sertpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., calibration tolerance uncertainties). The ESFAS setpoint value is therefore considered a “nominal” value (i.e., expressed as a value without inequalities) for the purposes of the COT and CHANNEL CALIBRATION.

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.

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 or superimposed on the field instrument signal. The process equipment for the channel in test is then tested, verified, and if required, calibrated. SRs for the channels are specified in the SR section.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of inputs from field contacts and control board switches and 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.

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BASES

BACKGROUND

Solid State Protection System (continued)

The input signals from field contacts, control board switches and 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 selected 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 relays with SLAVE RELAY TEST circuits available actual component operation can be prevented 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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. 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 were credited in the accident analysis. Specific information regarding the ESFAS Functions status as primary or backup actuation signal for a given accident is provided in FSAR Chapter 15 (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. 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. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions. Typically, failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of two, three or four 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:

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 (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to ≤ 2200°F); and

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

   2. Boration to ensure recovery and maintenance of SDM ($k_{eff} < 1.0$).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Purge Isolation;
- Start of Emergency Diesel Generators;
- Reactor Trip;
- Turbine Trip;
- SGFP Trip;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps; and
- Place the control room ventilation in the emergency mode of operation.

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Emergency Diesel Generators are operating in a standby condition to provide power should a subsequent LOSP occur;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) and SGFP trip to limit RCS cooldown, post-trip core power excursion, and containment building pressure and temperature rise due to secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

- Isolation, pressurization, and filtration of the control room to ensure habitability.

a. Safety Injection — Manual Initiation

The LCO requires two channels 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 ESF components in both trains in a similar manner as any of the automatic actuation signals. However, the reactor trip signal is initiated via the RTB shunt trip mechanisms.

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 manual switch and the interconnecting wiring to the actuation logic cabinet. Each manual switch actuates both trains. This configuration does not allow testing at power.

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 initiation from parameters reaching their setpoint 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 Initiation switches. Automatic Actuation Logic and Actuation Relays must be OPERABLE in MODE 4 to support system level Manual Initiation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

b. Safety Injection — Automatic Actuation Logic and Actuation Relays (continued)

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.

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 pressurize the containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

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.

Since no control function is provided by these channels, only three protection channels are necessary to satisfy the protective requirements in a two-out-of-three 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) 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 or the Steam Line Pressure – Low signal if not manually blocked at P-12, or the Steam Line Pressure – High Differential Pressure Between Steam Lines 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Safety Injection — Steam Line Pressure

(1) Steam Line Pressure — Low

Steam Line Pressure — Low provides protection against the following accidents:

- SLB; and
- Feed line break.

Three OPERABLE channels, one on each steam line, are sufficient to satisfy the protective requirements with a two-out-of-three logic.

With the transmitters located outside the main steam valve room, the Trip Setpoint reflects only steady state 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-12) 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-12 setpoint. Automatic SI actuation is provided by containment pressure — High 1 and/or High Differential Pressure between steam lines. Inside containment SLB will be terminated by automatic MSLI actuation via Containment Pressure — High 2, and outside containment SLB will be terminated by the High Steam flow in two steam lines coincident with Low – Low – T_{avg} 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 cause an accident.

(2) Steam Line Pressure — High Differential Pressure Between Steam Lines

Steam Line Pressure — High Differential Pressure Between Steam Lines provides protection against the following accidents:

- SLB;

(continued)

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

(2) Steam Line Pressure - High Differential Pressure Between Steam Lines (continued)

- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three protection set logic on each steam line.

With the transmitters located outside the main steam valve room, the Trip Setpoint reflects only steady state instrument uncertainties. Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

2. Containment Spray

Containment Spray provides two primary functions:

1. Lowers containment pressure and temperature after an HELB in containment; and
2. Reduces the amount of radioactive iodine in the containment atmosphere.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure; and
- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure.

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. When the RWST reaches the low low level setpoint, the spray pump suctions are shifted to the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Containment Spray (continued)

containment sump if continued containment spray is required. Containment spray is actuated manually or by Containment Pressure — High 3.

a. Containment Spray — Manual Initiation

The operator can initiate containment spray at any time from the control room by simultaneously turning two associated containment spray actuation switches. Because an inadvertent actuation of containment spray could have such serious consequences, two associated switches must be turned simultaneously to initiate containment spray. There are four switches in the control room. Simultaneously turning two associated switches will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two channels of Manual Initiation switches with two associated switches in each channel 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. Containment Spray — 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, paragraph 1.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential 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 initiation from Containment Pressure – High 3 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Containment Spray — Automatic Actuation Logic and Actuation Relays (continued)

the use of the Manual Initiation 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 – High 3

This signal provides protection against a LOCA or an SLB inside containment. 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 transmitters will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function 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 (disabled) rather than trip to decrease the probability of an inadvertent actuation.

The Containment Pressure High 3 instrument Function consists of a two-out-of-four logic configuration. Since containment pressure is not used for control, this arrangement exceeds the minimum redundancy requirements. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Containment Spray — Containment Pressure – High 3 (continued)

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 (except SW). 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 RCPs and instrument air, 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.

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation logic. CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and oil 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. Note that manual actuation of Phase A Containment Isolation also actuates Containment Purge and Exhaust Isolation.

The Phase B signal isolates CCW to the RCPs and instrument air to containment. This occurs at a relatively high containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Containment Isolation (continued)

pressure that is indicative of a large break LOCA or an SLB. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some system components do not meet all of the ASME Code requirements applied to the containment itself, the 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 and containment spray must have been actuated. Under these conditions, in conjunction with CCW isolation, RCP operation will no longer be favorable.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two associated switches are operated simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. Containment Isolation — Phase A Isolation

(1) Phase A Isolation — Manual Initiation

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 Purge 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, paragraph 1.

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 Initiation 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 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 that actuate Containment Spray, Function 2). The

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Containment Isolation — Phase B Isolation (continued)

Containment Pressure actuation of Phase B Containment Isolation is energized to actuate in order to minimize the potential of spurious actuation, which would be undesirable.

(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 initiation from Containment Pressure – High 3 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 Initiation 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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 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 line header depressurizes. Steam Line Isolation 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. Steam Line Isolation — Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are six switches in the control room and each switch can initiate action to immediately close the associated MSIV. The LCO requires one channel per steam line to be OPERABLE. Although two MSIVs per steam line are required OPERABLE by LCO 3.7.2, the Manual Initiation function for these valves is not credited in the safety analyses and redundant Manual Initiation per steam line is not required.

b. Steam Line 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, paragraph 1.

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 one MSIV in each Steam Line is closed. 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 one MSIV in each Steam Line is closed. In MODES 4, 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 - 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 a feed line break to ensure a supply of steam for the turbine driven AFW pump.

Steam Line Pressure — Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-12), when a secondary

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Steam Line Isolation — Steam Line Pressure – Low (continued)

side break could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-12 setpoint. Below P-12, 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 High flow in Two Steam Lines coincident with Tavg Low — Low signal for Steam Line Isolation below P-12 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless one MSIV in each Steam Line is closed. 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 an accident with any significant adverse consequences.

e. Steam Line Isolation — High Steam Flow in Two Steam Lines Coincident with T_{avg} — Low Low

This function provides closure of the MSIVs during an SLB or inadvertent opening of an SG relief or safety valve, to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment.

Two steam line flow channels per steam line are required OPERABLE for this Function. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows on-line testing because trip of one high steam flow channel is not sufficient to cause initiation. Steam line isolation on high steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the steam flow in the remaining intact steam lines will increase due to the fault in the other line. The increased steam flow in the remaining intact lines will actuate the required high steam flow trip. The Function trips on one-out-of-two high steam flow in any two-out-of-three steam lines if there is a one-out-of-one low low T_{avg} trip in any two-out-of- three RCS loops. The one channel per

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Steam Line Isolation — High Steam Flow in Two Steam Lines Coincident with T_{avg} — Low Low (continued)

loop and two-out-of-three RCS loop low low T_{avg} logic configuration allows on-line testing and since T_{avg} is an indication of bulk RCS temperature, it satisfies redundancy requirements.

The Trip Setpoint for high steam flow is a linear function that varies with power level, which is determined by turbine impulse chamber pressure. The function is a ΔP corresponding to 40% of full steam flow between 0% and 20% load to 110% of full steam flow at 100% load.

Although the high steam flow transmitters are located inside containment, the events this instrumentation Function protects against (steam line break outside containment) do not cause the transmitters to be exposed to a severe environment. The electronics associated with the RTDs used to determine T_{avg} are also not exposed to a severe environment as a result of the accident for which this instrumentation provides protection; therefore, the trip setpoints reflect only steady state environmental instrument uncertainties. The steam flow transmitters provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. The T_{avg} channels provide control inputs, but the control system incorporates a median signal selector for T_{avg}, which provides functional isolation between the control and protection systems.

This function must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless one MSIV in each steam line is closed. 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 an accident with any significant adverse consequences.

5. Turbine Trip and Feedwater Isolation

For the feedline and steamline events, the primary functions of the Turbine Trip and Feedwater Isolation (FWI) signals are to limit RCS cooldown, post-trip core power excursion, and containment building pressure and temperature rise due to secondary side mass losses.(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Turbine Trip and Feedwater Isolation (continued)

For the feedwater malfunction event (i.e., steam generator overfill), 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.

The Function is actuated when the level in any SG exceeds the high high setpoint, and performs the following functions:

- Trips the main turbine;
- Trips the MFW pumps; and
- Shuts the MFW regulating valves and the bypass feedwater regulating 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 automatically tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously. Interlock P-4 seals in the FWI signal to ensure main feedwater is not inadvertently added to an SG following reset of the automatic isolation signal. In addition, the SGFP discharge valves automatically close when the feedpumps trip to ensure that condensate water is not inadvertently added to a de-pressurized SG.

a. Turbine Trip and Feedwater 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, paragraph 1.

Portions of the Automatic Actuation Logic and all of the Actuation Relays are common to both SG Water Level – High High (P-14) and Safety Injection.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Turbine Trip and Feedwater Isolation (continued)

   b. Turbine Trip and Feedwater Isolation — Steam Generator Water Level — High High (P-14)

      This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. Therefore, the actuation logic 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. Since only three channels are installed, a median signal selector is installed for use with the SG Water Level Control System. The control and protection system interaction criteria of IEEE 279 is satisfied by the median signal selector and physically separate instrument lines and taps.

      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 is 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. In MODES 3, 4, 5, and 6, the MFW System and the turbine generator are not in service and 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Auxiliary Feedwater (continued)

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, during a steamline or Feedwater System pipe break, and during a small break LOCA. The normal source of water for the AFW System is the condensate storage tank (CST). The AFW System is aligned so that upon a pump start, flow is initiated to the SGs immediately.

a. Auxiliary Feedwater — 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, paragraph 1.

b. Auxiliary Feedwater — Steam Generator Water Level — Low Low

SG Water Level — Low Low provides protection against a loss of heat sink and feedline break. The SG water level setpoints are specified in percent of narrow range instrument span on each SG. 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. Since only three channels are installed, a median signal selector is installed for use with the SG Water Level Control System. The control and protection system interaction criteria of IEEE 279 is satisfied by the median signal selector and physically separate instrument lines and taps.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. 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.

Functions 6.a through 6.c must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. The Farley safety analyses assume two pumps operating to assure that the minimum required flow rate is delivered to the SGs for all postulated events. 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. Since the SG Low-Low level signal is credited in the safety analyses as the primary ESF signal for loss of heat sink events, periodic response time testing is required. SG Water Level — Low Low in any two operating SGs will cause the turbine driven pump to start. Since this signal provides backup protection for loss of heat sink events, periodic response time testing is not required. 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.

d. Auxiliary Feedwater — Undervoltage Reactor Coolant Pump

A loss of power on the buses that provide power to the RCPs provides indication of a pending loss of RCP forced flow in the RCS and a loss of power to the station auxiliaries. The SBLOCA analysis credits the TDAFW pump start by RCP bus UV as a primary ESFAS signal. The Undervoltage RCP Function senses the voltage on each RCP bus. Two UV sensors are associated with each bus (one for each logic train). Each RCP bus is assigned to a protection channel. The UV sensors and logic circuits are common to both the RCP UV reactor trip and the TDAFW pump ESF start (Unit 2 only). Separate UV sensors and logic circuits are provided for the RCP UV reactor trip and the TDAFW pump ESF start functions (Unit 1 only). A

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Auxiliary Feedwater — Undervoltage Reactor Coolant Pump (continued)

loss of power on two or more RCP buses, will start the turbine driven AFW pump to ensure that the available SGs contain enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

Function 6.d must be OPERABLE in MODES 1 and 2. This ensures that the available SGs are 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 RCPs may be normally shut down, and thus a loss of voltage on two or more RCP buses trip may not be indicative of a condition requiring automatic AFW initiation.

e. Auxiliary Feedwater — Trip of All Main Feedwater Pumps

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 MFW pump has two steam stop valves (HP and LP) for the turbine driver. Each MFW pump turbine stop valve is equipped with a limit switch that actuates when the valve is closed. When both MFW pumps are shut down (all four turbine stop valve limit switches are actuated), a start of the motor-driven AFW pumps is initiated. The four-out-of-four logic of this function is not single failure proof but is acceptable due to the backup nature of this AFW pump start function. This ESF function is not credited for diversity, and its electrical circuits are not required to the safety-grade. This function is not relied on in any safety analyses as the primary actuation signal to initiate the AFW pumps but is part of the licensing basis of the ESFAS. Therefore, two channels per pump are required OPERABLE to ensure this function is available if needed. The automatic start of the AFW pumps ensures that the available SGs are supplied with water to act as the heat sink for the reactor.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

e. Auxiliary Feedwater — Trip of All Main Feedwater Pumps (continued)

Function 6.e must be OPERABLE in MODE 1 to provide the automatic start of the motor-driven AFW pumps if needed. The automatic start of the AFW pumps ensures that the available SGs are supplied with water to act as the heat sink for the reactor in the event of an accident. In MODES 2, 3, 4, and 5, the MFW pumps may be normally shut down and thus the pump trip is not indicative of a condition requiring automatic AFW initiation.

7. 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 bypassable functions are in operation under the conditions assumed in the safety analyses.

a. Engineered Safety Feature Actuation System Interlocks-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, paragraph 1.

b. 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 are open. Once the P-4 interlock is enabled, if an SI has occurred, reset of the SI is allowed after a 60 second time delay. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once the SI is reset, automatic actuation of SI cannot occur until the RTBs have been manually closed. The additional functions of the P-4 interlock are:

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Engineered Safety Feature Actuation System Interlocks — Reactor Trip, P-4 (continued)

Control

- Block steam dump control via load rejection controller;
- Arm steam dump control for tripping and/or modulation of dump valves via turbine trip controller; and
- Isolate MFW with coincident low $T_{avg.}$

Safety

- Prevent auto reactuation of SI after a manual reset of SI;
- Trip the main turbine;
- Reset high steam flow setpoint to no-load value; and
- Prevent 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 generated power. Addition of feedwater to a steam generator associated with a steamline or feedline break could result in excessive containment building pressure. 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.

The turbine trip Function is explicitly assumed in the non-LOCA safety analyses, since it is an immediate consequence of the reactor trip Function. Block of the auto SI signals is required to support long-term ECCS operation in the post-LOCA recirculation mode.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Engineered Safety Feature Actuation System Interlocks — Reactor Trip, P-4 (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because automatic SI is not required in these modes and the main turbine and the MFW System are not in operation.

c. 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 from pressurizer Low pressure. 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 SI signal. The P-11 interlock provides the following two safety functions. With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure — Low SI actuation is automatically reinstated. To prevent uncontrolled RCS de-pressurization due to control system failure, the pressurizer PORVs are interlocked closed in the autocontrol mode, with two-out-of-three channels below the P-11 setpoint. The Trip Setpoint reflects steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to automatically reinstate SI during normal unit startup and to allow an orderly cooldown and depressurization of the unit without the actuation of a pressurizer low pressure SI. 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.

d. Engineered Safety Feature Actuation System Interlocks — T_{avg} — Low Low, P-12

On increasing reactor coolant temperature, the P-12 interlock safety function is to reinstate the SI and main steam isolation on Steam Line Pressure — Low with two-out-of-three channels above the setpoint. On decreasing reactor coolant temperature, to permit a normal unit cooldown, the P-12 interlock allows the operator to manually block SI and main

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Engineered Safety Feature Actuation System Interlocks — T_{avg} — Low Low, P-12 (continued)

steam isolation on Steam Line Pressure — Low. On decreasing temperature with two-out-of-three T_{avg} channels below the setpoint, the P-12 interlock safety function is to provide main steam isolation on high steam flow in two steam lines coincident with T_{avg} — Low Low. Another P-12 safety function on a decreasing temperature is for the P-12 interlock to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump Control System. The Trip Setpoint and Reset reflect steady-state instrument uncertainties.

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. These channels are used in two-out-of-three logic.

This Function must be OPERABLE in MODES 1, 2, and 3 to automatically reinstate SI and MSLI on Steam Line Pressure— Low when RCS T_{avg} is above the P-12 setpoint and to afford protection when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This Function is OPERABLE when the interlock is in the required state for the unit condition. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to have a design basis accident.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(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

(continued)

BASES

ACTIONS (continued)

Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, 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.

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

(continued)

BASES

ACTIONS

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

must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 4 within an additional 6 hours (60 hours total time). Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 19). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 19, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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; and
- Phase B Isolation.

This Condition is intended to address an inoperability of the actuation logic or relays associated with a given train which affects the integrated ESFAS response to an actuation signal. This Condition is applicable whenever more than one ESF system is affected by the inoperable train of logic or relays. However, if one or more inoperable actuation relay(s) in a train affect only a single ESF system, then the ACTIONS Condition of the LCO applicable to the affected ESF component or system should be entered and this Condition is not applicable.

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 11. 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 overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 4 within an additional 6 hours (36 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.

Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 19). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 19, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

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BASES

ACTIONS

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

Required Action C.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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. 10) that 4 hours is the average time required to perform train surveillance.

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

Condition D applies to:

- Containment Pressure — High 1;
- Pressurizer Pressure — Low;
- Steam Line Pressure — Low;
- Steam Line Differential Pressure — High;
- Containment Pressure — High 2;
- High Steam Flow in Two Steam Lines Coincident With T_{avg} — Low Low; 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 configuration. One channel must be

(continued)

BASES

ACTIONS

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

tripped to place the Function in a partial trip condition where one-out-of-two Logic will result in actuation. This configuration 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 11.

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 the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 12 hours allowed for testing are justified in Reference 11.

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 and Phase B isolation. Spurious spray actuation is undesirable because of the cleanup problems presented and Phase B isolation is undesirable because of CCW to RCP thermal barrier and oil cooler isolation. 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.

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BASES

ACTIONS

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

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 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 one additional channel to be bypassed for up to 12 hours for surveillance testing. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on the results of Reference 11.

F.1, F.2.1, and F.2.2

Condition F applies to Manual Initiation of Steam Line Isolation and the P-4 interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. 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 function 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.

This Condition is intended to address an inoperability of the actuation logic or relays associated with a given train which affects the integrated ESFAS response to an actuation signal. This Condition is applicable whenever more than one ESF system is affected by the inoperable train of logic or relays. However, if one or more inoperable actuation relay(s) in a train affect only a single ESF system, then the ACTIONS Condition of the LCO applicable to the affected ESF component or system should be entered and this Condition is not applicable.

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 11. 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 Reference 11 and 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. 10) assumption that 4 hours is the average time required to perform channel surveillance.

(continued)

BASES

ACTIONS (continued)

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 Condition is intended to address an inoperability of the actuation logic or relays associated with a given train which affects the integrated ESFAS response to an actuation signal. This Condition is applicable whenever more than one ESF system is affected by the inoperable train of logic or relays. However, if one or more inoperable actuation relay(s) in a train affect only a single ESF system, then the ACTIONS Condition of the LCO applicable to the affected ESF component or system should be entered and this Condition is not applicable.

This action addresses the train orientation of the SSPS and the master and slave relays 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 11. 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 Reference 11 and 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.

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. 10) assumption that 4 hours is the average time required to perform channel surveillance.

(continued)

BASES

ACTIONS (continued)

I.1 and I.2

Condition I applies to:

- SG Water Level — High High (P-14); and
- Undervoltage Reactor Coolant Pump.

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. For RCP UV, both sensors associated with a given channel must be tripped (or, if applicable, bypassed) to satisfy the requirements of Action I.1. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 11. 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 78 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 the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. 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 11.

J.1

Condition J applies to the AFW pump start on trip of all MFW pumps.

This action addresses the loss of one or more MFW pump trip channels on one or more MFW pumps. The failure of any one of the four channels (2 per pump) to actuate would prevent this function from initiating a start of the motor-driven AFW pumps. This Condition is intended to address the loss of this ESFAS function by any number of inoperable channels. In order to ensure this function is OPERABLE and capable of initiating a start of the motor-driven AFW pumps, all inoperable channels must be restored to OPERABLE status prior to the next required TADOT surveillance. The allowance for this function

(continued)

BASES

ACTIONS

J.1 (continued)

to be lost and the associated Completion Time of prior to the next required TADOT surveillance are acceptable based on the backup nature of this function. This function is not relied on as the primary actuation signal for AFW auto-start in any DBA analysis.

K.1, K.2.1, and K.2.2

Condition K applies to the P-11 and P-12 interlocks. This Condition is applicable when the interlock is inoperable to the extent that an ESFAS function which should not be blocked in the current MODE is blocked.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. 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.

L.1, L.2, L.3.1, and L.3.2

Condition L applies to the automatic actuation logic and actuation relays for the P-4, P-11 and P-12 interlocks. This Condition is applicable when the interlock is inoperable to the extent that an ESFAS function which should not be blocked in the current MODE is blocked.

With one train inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the interlock must be restored to OPERABLE status within 24 hours, or the unit must be placed in MODE 3 within the next 6 hours and

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BASES

ACTIONS

L.1, L.2, L.3.1, and L.3.2 (continued)

MODE 5 within the following 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. Placing the unit in MODE 5 removes all requirements for OPERABILITY of these interlocks and the automatic actuation logic, SI actuation relays and interlock actuation relays.

This Condition is intended to address an inoperability of the actuation logic or relays associated with a given train which affects the integrated ESFAS response to a pressurizer low pressure SI (P-11), steam line low pressure SI/MSLI (P-12), or any auto SI (P-4) actuation signal. This Condition is applicable whenever more than one ESF system is affected by the inoperable train of logic or relays. However, if one or more inoperable actuation relay(s) in a train affect only a single ESF system, then the ACTIONS Condition of the LCO applicable to the affected ESF component or system should be entered and this Condition is not applicable.

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 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 that 4 hours is the average time required to perform channel surveillance (Ref. 10).

BASES

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 (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.

<u>SR 3.3.2.1</u>

Performance of the CHANNEL CHECK 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

<u>SR 3.3.2.2</u>

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST using the semiautomatic tester. The train being tested is placed in the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2 (continued)

bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection and permissive function excluding the automatic actuation Logic for the trip of all main feedwater pumps. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.2.3

SR 3.3.2.3 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. The time allowed for the testing on a STAGGERED TEST BASIS (4 hours) is justified in Reference 10. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the rack components will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1. With the exception of P-11, the COT also confirms the channel inputs to both actuation logic trains. The P-11 inputs are tested under SR 3.3.2.7.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

The "as found" and "as left" data have been evaluated to ensure consistency with (i.e., bounded by) the drift allowance used in the setpoint methodology. The COT "as found" limits are based, in part, on expected performance of a healthy instrument channel. Appropriate corrective action is taken when the "as found" values exceed the prescribed values. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a TADOT. This test is a check of the Undervoltage RCP Function. The Function is tested up to the SSPS logic circuit. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The test includes undervoltage sensing devices that provide actuation signals directly to the SSPS. The test functionally demonstrates channel OPERABILITY including verification of the trip setpoint. If necessary, the undervoltage setpoint is restored to within calibration tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and the P-4 interlock Function, including turbine trip, automatic SI block, and seal-in of FWI by SI. 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 (i.e., pump starts, valve cycles, etc.). The turbine trip by reactor trip (P-4) is independently verified for both trains. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The manual initiation and P-4 interlock Functions have no associated setpoints.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a CHANNEL CALIBRATION.

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 "as found" and "as left" data have been evaluated to ensure consistency with (i.e., bounded by) the drift allowance used in the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 3.3.2.8

SR 3.3.2.8 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 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 or is tested when there will be no adverse impact on the plant. For this latter case, when using the SLAVE RELAY TEST circuit, contact operation is verified by a continuity check of the circuit containing the slave relay. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. While the ESFAS is designed to accommodate online testing at power, slave relay testing is normally conducted during refueling to minimize the potential for plant transients and unnecessary challenges to plant equipment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.9

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 acceptance criteria are included in the FSAR, Table 7.3-16 (Ref. 13). Individual component response times are not typically 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 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 test may be performed with the transfer functions set to one or with the time constants set to their nominal value. The test results must be compared to properly defined acceptance criteria.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel in any series of sequential or overlapping measurements. Allocations for specific pressure and differential pressure sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications.

WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," (Ref. 14) provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," (Ref. 15) provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for the sensor, signal processing and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

electric repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where time response could be affected is replacing the sensing assembly of a transmitter.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 1005 psig in the SGs. Based on operating experience, 24 hours is a sufficient time duration for performance of the TDAFW pump response time test. A steam pressure of 1005 psig corresponds to the RCS no-load T_{avg} for MODE 2. Valid response time tests can be performed at lower SG pressures.

SR 3.3.2.10

SR 3.3.2.10 is the performance of a TADOT as described in SR 3.3.2.6, except that it is performed for the AFW pump start on trip of all MFW pumps Function and the Frequency is prior to reactor startup if not performed within the previous 92 days. 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.

(continued)

BASES

REFERENCES (continued)

3. FSAR, Chapter 15.

4. Joseph M. Farley Nuclear Power Plant Unit 1 (2) Precautions, Limitations, and Setpoints U–266647 (U–280912).

5. IEEE-279-1971.

6. WCAP 13751, Rev. 1, Westinghouse Setpoint Methodology for Protection Systems Farley Nuclear Plant Units 1 and 2.

7. 10 CFR 50.49.

8. WCAP 13751 Rev. 0, Westinghouse Setpoint Methodology for Protection Systems SNOC Farley Nuclear Plant Units 1 and 2.

9. Not used.

10. WCAP-10271-P-A, Supplement 2, Rev. 1, "Updated Approved Version," June 1990.

11. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

12. Not used.

13. FSAR, Table 7.3-16.

14. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," Jan., 1996.

15. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," Oct. 1998.

16. NUREG-1218, April 1988.

17. A-181007 Reactor Protection System FSD.

18. Westinghouse Functional Diagrams U-166231 thru U-166245.

19. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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 and certain Category I variables.

Type A 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.

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

- Determine whether other systems important to safety are performing their intended functions;

(continued)

BASES

BACKGROUND (continued)

- 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 release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

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 certain Category I 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;

- 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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). The specified Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, 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 certain Regulatory Guide 1.97 instruments that have been designated Category I, 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 for most Functions. Two OPERABLE channels 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.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

Table 3.3.3-1 lists all Type A and certain Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER.

(continued)

BASES

LCO (continued)

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (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, 2. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

RCS Hot and Cold Leg Temperatures are Category I, Type A variables provided for verification of core cooling and long term surveillance.

RCS hot and cold leg temperatures are used to determine RCS subcooling margin. 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.

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.

Reactor inlet and outlet temperature inputs to the Reactor Protection System are provided by two fast response resistance elements in each loop. The channels provide indication over a range of 0°F to 700°F.

3. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I, Type A variable provided for verification of core cooling and RCS integrity long term surveillance.

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).

(continued)

BASES

LCO

3. Reactor Coolant System Pressure (Wide Range) (continued)

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.

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 also 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.

(continued)

BASES

LCO (continued)

4. Steam Generator Water Level (Wide and Narrow Range)

SG Water Level is provided to monitor operation of decay heat removal via the SGs. The Category I, Type A indication of SG level includes both the wide and narrow range instrumentation. The wide range level covers a span of 12 inches to 587 inches above the lower tubesheet. The measured differential pressure is displayed in percent level at 70°F.

Temperature compensation of this indication is performed manually by the operator. Redundant monitoring capability is provided by multiple level channels on each SG. The uncompensated level signal is input to the plant computer and a control room indicator.

SG Water Level 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.

Operator action is based on the control room indication of SG level. SG level is a Type A variable because the operator must manually raise and control SG level to establish the required heat sink. Operator action is initiated on a loss of minimum level or minimum AFW flow. Feedwater flow is increased until the indicated level reaches a point where an adequate heat sink is being maintained.

5. Refueling Water Storage Tank (RWST) Level

The RWST level is a Category I, Type A variable provided for verifying a water source to the Emergency Core Cooling Systems (ECCS) and Containment Spray System. It is used to determine the time for initiation of cold leg recirculation following a LOCA.

The RWST level accuracy is established to allow an adequate supply of water to the ECCS and spray pumps during the

(continued)

LCO

5. Refueling Water Storage Tank (RWST) Level (continued)

switchover to cold leg recirculation mode. A high degree of accuracy is required to maximize the time available to the operator to complete the switchover to the sump recirculation phase and ensure sufficient water is available to avoid losing pump suction.

6. Containment Pressure (Narrow Range)

Containment Pressure (Narrow Range) is a Category I, Type A variable provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to verify closure of main steam isolation valves (MSIVs) on High–2 Main Steam Line Isolation, and containment spray Phase B isolation when High-3 containment pressure is reached as well as manual actuation of containment spray if necessary.

7. Pressurizer Level

Pressurizer Level is a Category I, Type A variable 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 that the unit is maintained in a safe shutdown condition.

8. Steam Line Pressure

Main Steam line pressure is a Category I, Type A variable provided for the following:

- Determining if a high energy secondary line rupture occurred and which SG is faulted;
- Maintaining the plant in a cold shutdown condition;
- Monitoring the primary to SG differential pressure during plant cooldown rate; and
- Providing diverse indication to cold leg temperature for natural circulation determination.

(continued)

BASES

LCO

8. Steam Line Pressure (continued)

Two channels of main steam pressure per SG are required OPERABLE. The instrumentation has sufficient accuracy to determine the faulted SG and to verify cold leg temperature for natural circulation.

9. Auxiliary Feedwater Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs.

One flow indication channel per SG is provided. Each differential pressure transmitter provides an input to a control room indicator and the plant 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.

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 a Category I, Type A variable because it is used by the operator to verify that the AFW System is delivering the correct flow to each SG and to identify a faulted SG or a SG with a tube rupture. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

(continued)

BASES

LCO (continued)

10. RCS Subcooling Margin Monitor

RCS subcooling is a Category II, Type A variable provided to determine safety injection termination and reinitiation and depressurization and cooldown progression. The subcooled margin monitor (SMM) measures saturation/superheat margin. The function of the SMM is to calculate the subcooled margin which is the difference between the measured temperature of the reactor coolant and the saturation temperature. The saturation temperature is calculated from the minimum primary system pressure input. A maximum or representative temperature input is used for the measured value, which could come from an RTD loop, or a representative core exit thermocouple.

11. Containment Sump Water Level (Wide Range)

Containment Sump Water Level is a Category I, Type A variable provided for verification and long term surveillance of RCS integrity. This information provides a diverse means for checking RWST level.

Containment Sump Water Level is used to determine:

- containment sump level accident diagnosis; and
- when to begin the recirculation procedure.

12, 13, 14, 15. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

Adequate monitoring of core cooling is ensured with two valid Core Exit Temperature channels per quadrant with two core exit thermocouples (CETs) per required channel. The CET pair are oriented radially to permit evaluation of core radial decay power distribution. Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

(continued)

LCO 12, 13, 14, 15. Core Exit Temperature (continued)

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. The two thermocouples in each channel must be located such that the pair of Core Exit Temperatures indicate the radial temperature gradient across their core quadrant consistent with the requirements of NUREG – 0737 (Ref. 3). Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.

16. Reactor Vessel Water Level

Reactor Vessel Water Level is a Category I variable provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy. A channel is a probe with eight sensors. A channel is OPERABLE if at least four sensors are OPERABLE.

The reactor vessel water level is derived from the heated junction thermocouple (HJTC) system. The HJTC system is part of the inadequate core cooling monitoring system (ICCMS). The HJTC system consists of thermocouples strategically located at different heights in the reactor vessel. The reactor vessel water level indicating system provides an indirect measurement of the collapsed liquid level at various plateaus above the upper core plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the upper core plate. Measurement of the collapsed liquid level is selected because it is a direct indication of the water inventory.

(continued)

BASES

LCO (continued)

17. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. The CST consists of a tank and outlet header. Inventory is monitored by two .5 – 11 feet of water indications for the tank. CST Level is displayed on control room indicators, and plant computer. In addition, control room annunciators alarm on low and low-low level.

CST Level is considered a Category I, Type A variable because the control room meter and annunciator are considered the primary indication used by the operator.

The DBAs that require AFW are the loss of offsite power, steam line break (SLB), 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 the Service Water System.

18. Deleted.

19. Containment Area Radiation (High Range)

Containment Area Radiation is a Category I variable 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. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

(continued)

BASES

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.

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 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.

(continued)

BASES

ACTIONS (continued)

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. This report discusses the results of the root cause evaluation of the inoperability, if performed, and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). 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.

(continued)

BASES

ACTIONS (continued)

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C are 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.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are 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 utilized 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 required to mitigate 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. The alternate means of monitoring the affected PAM Channel should be identified or installed, if necessary, prior to submitting the report to the NRC. An acceptable alternate means of monitoring Reactor Vessel Water Level is to monitor pressurizer level and upperhead subcooling.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK 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. The high radiation instrumentation should be compared to similar unit instruments.

Agreement criteria are 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. A-181866 Unit 1 RG 1.97 Compliance Review
   A-204866 Unit 2 RG 1.97 Compliance Review
   NRC SER for FNP RG 1.97 Compliance Report, Letter, Reeves to McDonald, 2/12/87.

2. Regulatory Guide 1.97.

3. NUREG-0737, Supplement 1, "TMI Action Items."

Table B 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

PAM INSTRUMENTATION	TPNS
RCS Hot Leg Temperature (Wide Range)	TE-413, TE-423, TE-433
RCS Cold Leg Temperature (Wide Range)	TE-410, TE-420, TE-430
RCS Pressure (Wide Range)	PT-402, PT-403
Steam Generator (SG) Water Level	Wide Range – LT-477, LT-487, LT-497
	Narrow Range – LT-474, LT-475, LT-476 LT-484, LT-485, LT-486 LT-494, LT-495, LT-496
Refueling Water Storage Tank Level	LT-501, LT-502
Containment Pressure (Narrow Range)	PT-950, PT-951, PT-952, PT-953
Pressurizer Water Level	LT-459, LT-460, LT-461
Steam Line Pressure	PT-474, PT-475, PT-476 PT-484, PT-485, PT-486 PT-494, PT-495, PT-496
Auxiliary Feewater Flow Rate	FT-3229A, FT-3229B, FT-3229C
RCS Subcooling Margin Monitor	Q1(2) H11NGCCM2523A&B
Containment Water Level (Wide Range)	LT-3594A, LT-3594B
Core Exit Temperature	TE-2301 – TE-2351
Reactor Vessel Level Indicating System	LE-2352, LE-2353
Condensate Storage Tank Level	LT-515, LT-516
Containment Area Radiation (High Range)	RE-27A, RE-27B

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (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 panels, and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the hot shutdown panels. Some controls and transfer switches will have to be operated locally at the switchgear, motor control centers, 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 remote shutdown control and 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.

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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it has been retained in the Technical Specifications as indicated in 10 CFR 50.36(c)(2)(ii).

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 instrumentation and controls required are listed in Table B3.3.4-1.

The controls, instrumentation, and transfer switches (where applicable) are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and SG ARVs;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators.

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE. However, not all control and transfer circuits in every system identified on Table B3.3.4-1 are required OPERABLE in order to support the required remote shutdown function. For example, the capability to remotely operate a single AFW pump and associated flow control valve and at least one associated SG atmospheric relief valve support an OPERABLE decay heat removal function. All the control and transfer circuits associated with all three AFW pumps do not have to be OPERABLE to support an OPERABLE decay heat removal function. A remote shutdown function is not inoperable until insufficient control and transfer circuits remain OPERABLE to perform the required function.

(continued)

BASES

LCO (continued)

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. 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 Remote Shutdown System division is inoperable when each function is not accomplished by at least one designated Remote Shutdown System Channel that satisfies the OPERABILITY criteria for the channel's function. These criteria are outlined in the LCO section of the Bases.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes the control and transfer switches for any required Function.

(continued)

BASES

ACTIONS

A.1 (continued)

The Required Action is to restore the required Function 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

A Note modifies Condition B indicating that it is not applicable to the Source Range Neutron Flux (Gammametrics) Function. This Function is covered under Condition C.

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.

C.1

Condition C applies when the Required Action and associated Completion Time for Condition A are not met for the Source Range Neutron Flux (Gammametrics) monitor. This Required Action requires a written report be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability, if performed, and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

Performance of the CHANNEL CHECK 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

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 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System control circuit and transfer switch performs the intended function. This verification is performed from the remote 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the monitoring instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

Table B3.3.4-1 (page 1 of 1)
Remote Shutdown System Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF CHANNELS
MONITORING INSTRUMENTATION	
1. Steam Generator Wide Range Level	1/SG
2. Steam Generator Pressure	1/SG
3. Pressurizer Water Level	1
4. Pressurizer Pressure	1
5. RCS Hot Leg Temperature (Loop A)	1
6. RCS Cold Leg Temperature (Loop A)	1
7. Source Range Neutron Flux (Gammametrics)	1
8. Condensate Storage Tank Level	1
TRANSFER AND CONTROL CIRCUITS	
9. Reactivity Control	
a. Boric Acid Transfer System	1
10. RCS Pressure	
a. Pressurizer Heater Control	1
11. RCS Inventory	
a. Charging System	1
b. Letdown Orifice Isolation Valves	1
12. Decay Heat Removal	
a. Auxiliary Feedwater System	1
b. SG Atmospheric Relief Valves	1
13. Safety Grade Support Systems Required For Functions Listed Above	1

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Engineered Safety Features (ESF) systems is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. Offsite power is the preferred source of power for the 4.16 kV emergency buses which power the required ESF components. The LOP protection instrumentation monitors voltage on the F and G 4.16 kV buses. Each electrical train has independent LOP instrumentation and relay actuation logic for detecting degraded grid or loss of voltage conditions, and initiating an LOP emergency diesel generator (EDG) start signal. There are three LOP protection instrumentation actuation levels.

The first level of protection consists of a single independent channel providing a degraded grid voltage alarm. This alarm is set at ≥ 3850V. This setpoint is based on detection of a degrading voltage condition where the bus voltage is below the minimum expected based on studies of the expected operation of the offsite power system. The alarm has a time delay to reduce the possibility of nuisance alarms for expected voltage transients.

The second level is set for each 4.16 kV emergency bus as tabulated in Technical Specification 3.3.5. This level generates an LOP signal for sustained degraded grid voltage conditions. The delay time setting prevents an unnecessary LOP by ensuring the existence of a sustained voltage inadequacy before actuation.

The third level is set at ≥ 3255V. This level generates an LOP signal for near instantaneous loss of voltage conditions. The inverse time setting provides quick detection of a significant voltage inadequacy while preventing an unnecessary LOP for momentary power system disturbances.

The second and third levels provide LOP actuation signals. Each level consists of three undervoltage relays (i.e., channels) arranged in a two-out-of-three logic. Actuation of either protection level will automatically disconnect the 4.16 kV emergency buses from the offsite power source. The loss of voltage sensors start the EDGs, and following the bus load shed, the Emergency Sequencer automatically reloads the bus.

(continued)

BASES

BACKGROUND (continued)

The LOP instrumentation is also discussed in FSAR, Section 8.3 (Ref.1).

Alarm/Trip Setpoints and Allowable Values

The actual nominal Alarm/Trip Setpoint entered into the device is normally still 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, providing the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values and/or Alarm/Trip Setpoints are specified for each Function in the LCO. Nominal Alarm or Trip Setpoints are also specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the device is performing as required. If the measured setpoint does not exceed the Allowable Value, the device is considered OPERABLE. Operation with an Alarm or Trip Setpoint less conservative than the nominal value, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the setpoint calculation.

Each Allowable Value and/or Alarm/Trip Setpoint specified is more conservative than the analytical limit specified in the voltage analyses to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in the setpoint calculation (Ref. 3).

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the ESF Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Safety analyses credit the loading of the DG based on concurrent loss of offsite power and a loss of coolant accident (LOCA). The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

actual DG start has historically been associated with the ESFAS actuation. The DG loading is included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

Monitoring by the offsite power system grid operators and the first level LOP instrumentation (alarm) provide the primary protection for a degraded grid event. The degraded grid voltage alarm provides notification to control room operators that an abnormally low voltage condition exists on a 4.16 kV emergency bus. For slow acting transient conditions, the alarm setpoint allows for the initiation of manual actions by the offsite power system operator to restore normal bus voltage and protect required ESF LOCA loads from the low voltage condition without initiating an unnecessary automatic disconnect from the preferred offsite power source.

For the 4.16 kV emergency buses to which Technical Specification Table 3.3.5-1 is applicable, an administrative limit is established at a voltage level between the degraded grid voltage alarm allowable value (3835V) and the automatic degraded grid voltage actuation upper allowable value (3749V). Calculations verify that no ESF components require a 4.16kV bus voltage higher than the administrative limit to perform their safety functions. In the voltage range between the administrative limit and the degraded grid voltage actuation trip setpoint, a few ESF components may not have automatic protection from inadequate voltage. The manual actions provide the primary means of protecting these few ESF components from a sustained, slightly low voltage condition and all components from unnecessary automatic disconnection from the preferred offsite power source.

For the 4.16 kV emergency buses to which Technical Specification Table 3.3.5-2 is applicable, an analytical limit is established for each bus at a voltage level below the automatic degraded grid voltage actuation allowable value shown in Table 3.3.5-2. Calculations verify that no ESF components require a 4.16 kV bus voltage higher than the analytical limit to perform their safety functions.

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 FSAR, Section 15 (Ref. 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 bound the 12 second DG start delay and include the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that three channels per train of both the loss of voltage and degraded grid voltage actuation Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the three channels must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. 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.

In addition, the LCO requires one channel of the degraded grid alarm function per train of 4.16 kV emergency buses to be OPERABLE in MODES 1, 2, 3, and 4. The required alarm channels include the Digital Voltmeter Relay Contacts (LO-27V) on buses F and G and the associated alarm annunciators WE2, VE2 (Unit 1) and YE2, ZE2 (Unit 2). The alarm channels provide assurance that manual actions are taken to restore bus voltage and protect the required ESF LOCA loads from a degraded grid voltage condition.

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. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

(continued)

BASES

APPLICABILITY (continued)

For the 4.16 kV emergency buses to which Technical Specification Table 3.3.5-1 is applicable, the degraded grid alarm function is required OPERABLE in MODES 1, 2, 3, and 4 to support the voltage requirements of the ESF loads required OPERABLE to mitigate a design basis LOCA. In MODES 5 and 6, the degraded grid alarm function is not required OPERABLE as no design basis LOCA is assumed to occur in these MODES and most of the ESF loads required to mitigate a design basis LOCA are not required OPERABLE.

For the 4.16 kV emergency buses to which Technical Specification Table 3.3.5-2 is applicable, the degraded grid alarm is not a function included in the Technical Specifications.

ACTIONS

In the event a channel's Alarm or 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 train basis, the Condition may be entered separately for each train as appropriate.

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 the LOP DG start Functions (Functions 1 and 2) with one loss of voltage or degraded grid voltage channel per train 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 remaining LOP DG start instrumentation channels will provide a one-out-of-two logic to initiate a trip of the incoming offsite power.

A Note is added to Condition A indicating that it is only applicable to Functions 1 and 2.

(continued)

BASES

ACTIONS

A.1 (continued)

A Note is added to allow bypassing an inoperable channel for up to 4 hours for surveillance testing of other channels. This allowance is made where bypassing the channel does not cause an actuation and where at least two other channels are monitoring that parameter.

The specified Completion Time and time allowed for bypassing one channel are reasonable considering the Function remains fully OPERABLE on each train and the low probability of an event occurring during these intervals.

B.1

Condition B applies to LOP Functions 1 and 2 when two or more loss of voltage or degraded voltage channels on a single train are inoperable.

A Note is added to Condition B indicating that it is only applicable to Functions 1 and 2.

Required Action B.1 requires restoring all but one channel on a train to OPERABLE status. With a single inoperable channel remaining on a train, Condition A is applicable. 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.

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources — Operating," or LCO 3.8.2, "AC Sources — Shutdown," 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.

(continued)

BASES

ACTIONS (continued)

D.1

Condition D applies when the required degraded grid voltage alarm function is inoperable on one or both trains of emergency buses. The affected bus voltage associated with each inoperable alarm function must be verified ≥ 3850 volts every 4 hours. Frequent bus voltage verifications in lieu of an OPERABLE alarm effectively accomplish the same function as the alarm and allow operation to continue without the required alarm(s). A Note is added to Condition D indicating that it is only applicable to Function 3.

E.1

Condition E is applicable when the Required Action and associated Completion Time of Condition D is not met. If the voltage being verified per Required Action D.1 is < 3850 volts, action must be taken to restore the voltage to ≥ 3850 volts within one hour. The Completion Time of one hour is reasonable to ensure prompt action is taken to restore adequate voltage to the affected emergency bus(es).

F.1 and F.2

Condition F becomes applicable when the Required Action and associated Completion Time of Condition E is not met. If the emergency bus voltage cannot be restored to ≥ 3850 volts within the Completion Time of Condition E, action must be taken to place the unit in a MODE where the LCO requirement for the Alarm function is 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment.

The TADOT surveillance is modified by two Notes. The first Note excludes the actuation of the final trip actuation relay for LOP Functions 1 and 2 from this TADOT. The actuation of this relay would

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1 (continued)

cause the DG start and separation of the emergency buses from the grid. The actual DG start and connection to the emergency bus is verified by other surveillance testing (SR 3.3.5.3) accomplished during shutdown conditions. The second Note provides an exception to the verification of the LOP function setpoints during performance of this monthly TADOT. The TADOT includes verification of the undervoltage device operation upon removal of the input voltage and does not require the setpoint be verified or adjusted. The LOP function setpoints are verified during the CHANNEL CALIBRATION. In addition, the TADOT includes verification of the operation of the two-out-of-three logic associated with LOP Functions 1 and 2. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded grid voltage test, shall include a single point verification that the trip occurs within the required time delay (refer to appropriate relay setting sheet calibration requirements).

The CHANNEL CALIBRATION is a check of the major instrument components in the loop, including the sensor (relay or digital voltmeter). The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The CHANNEL CALIBRATION is modified by a Note. The Note excludes the actuation of the final trip actuation relay for LOP functions 1 and 2 from this CHANNEL CALIBRATION. The actuation of this relay would cause the DG start and separation of the emergency buses from the grid. The actual DG start and connection to the emergency bus is verified by other surveillance testing (SR 3.3.5.3) accomplished during shutdown conditions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

This SR ensures the individual channel response times are less than or equal to the maximum values assumed in the safety analysis. The response time testing acceptance criteria are included in FSAR Table 7.3-16. This surveillance is performed in accordance with the guidance provided in the ESF RESPONSE TIME surveillance requirement in LCO 3.3.2, ESFAS.

This surveillance is modified by a Note. The Note states that this surveillance shall include verification of the actuation of the final trip actuation relay associated with LOP Functions 1 and 2.

REFERENCES

1. FSAR, Section 8.3.

2. FSAR, Chapter 15.

3. SNC Calculations E-35.1.A, E-35.2.A, SE-94-0470-006 and SJ-SNC529029-001.

4. FSAR, Section 7.3.

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge and Exhaust Isolation Instrumentation

BASES

BACKGROUND

Containment purge and exhaust isolation instrumentation closes the containment isolation valves in the Mini Purge System and the Main Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Mini Purge System may be in use during reactor operation and the Main Purge System will be in use with the reactor shutdown.

Containment purge and exhaust isolation initiates on a automatic safety injection (SI) signal through the Containment Isolation — Phase A Function, or by manual actuation of Phase A Isolation or manual initiation of the associated valve handswitches. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss these modes of initiation.

Two radiation monitoring channels are also provided as input to the containment purge and exhaust isolation. The two channels measure radiation in a sample of the containment purge exhaust. The purge exhaust radiation detectors are gaseous type monitors. Both detectors will respond to events that release radioactivity to containment. Therefore, for the purposes of this LCO the two channels are considered redundant. Since the purge exhaust monitors constitute a sampling system, various components such as sample line valves and sample pumps are required to support monitor OPERABILITY.

Each of the purge systems has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from either detector initiates containment purge isolation, which closes containment isolation valves in the Mini Purge System and the Main Purge System. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event. The isolation of the purge valves has not been analyzed in the dose calculations, although its rapid isolation is assumed. The containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

purge and exhaust isolation radiation monitors act as backup to the SI signal to ensure closing of the purge and exhaust valves. They are also the primary means for automatically isolating containment in the event of a fuel handling accident during shutdown. 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 50.67 (Ref. 1) limits.

The containment purge and exhaust isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Purge and Exhaust Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation

   The LCO requires two channels OPERABLE. The operator can initiate Containment Purge Isolation at any time by using either of two valve hand switches in the control room (labeled CTMT PURGE DMPRS). Each switch actuates one train of purge/exhaust isolation valves. Actuation of either handswitch isolates the Containment Purge and Exhaust System.

   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 handswitch and the interconnecting wiring to the purge/exhaust isolation valves in that train.

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 (Paragraph 1), SI, and ESFAS Function 3.a,

(continued)

BASES

LCO

2. Automatic Actuation Logic and Actuation Relays (continued)

Containment Phase A Isolation. The Actions Conditions for the containment purge 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 Purge 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 Purge Isolation Functions specify sufficient compensatory measures for this case.

3. Containment Radiation

The LCO specifies one required channel of radiation monitor in MODES 1-4 and two radiation monitoring channels during CORE ALTERATIONS or movement of irradiated fuel assemblies in containment to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY also requires correct valve lineups and sample pump operation, as well as detector OPERABILITY.

4. Containment Isolation — Phase A

Refer to LCO 3.3.2, Function 3.a., for all initiating Functions and requirements except as described above in item 2, "Automatic Actuation Logic and Actuation Relays."

APPLICABILITY

The Automatic Actuation Logic and Actuation Relays and Containment Isolation — Phase A Functions are required OPERABLE in MODES 1, 2, 3 and 4. The Manual Initiation and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4, and 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

(continued)

BASES

APPLICABILITY (continued)

radioactivity into containment. Therefore, the containment purge and exhaust isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without fuel handling in progress, the containment purge and exhaust isolation instrumentation need not be OPERABLE since the 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 purge and exhaust isolation on the ESFAS Containment Isolation Phase A Functions is specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for 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. 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 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.

<u>A.1</u>

Condition A applies to the failure of one required containment purge isolation radiation monitor channel. The failed 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, and recognition that the radiation monitor provides

(continued)

ACTIONS

A.1 (continued)

backup protection to the Phase A Isolation signal in MODES 1-4 and that during the Applicability of CORE ALTERTIONS or movement of irradiated fuel assemblies in containment the remaining radiation monitoring channel remains capable of responding if required.

B.1

Condition B applies to all Containment Purge and Exhaust Isolation Functions and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for these Functions as well as the manual handswitches for the isolation valves. It also addresses the inability to restore a single failed radiation monitor channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are 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 stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

C.1 and C.2

Condition C applies to the Containment Purge and Exhaust Manual Isolation Function. It also addresses the failure of two radiation monitoring channels, or the inability to restore a single failed radiation monitor channel to OPERABLE status in the time allowed for Required Action A.1. If one or more manual handswitch channels(s) are inoperable, or two radiation monitor channels are inoperable, or 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 purge and exhaust isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation (which includes manual handswitch channel(s)). The Completion Time for these Required Actions is Immediately.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

A Note states that Condition C is applicable during the Applicability of 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 Purge and Exhaust Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2 (continued)

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.6.4

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. 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 unit specific calibration procedure tolerance.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 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 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 the slave relay.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.6.6

SR 3.3.6.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. 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 (i.e., pump starts, valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the SSPS, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.7

The 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.8

This SR ensures the individual channel response times are less than or equal to the maximum values assumed in the safety analysis. The response time testing acceptance criteria are included in FSAR Table 7.3-16 (Ref. 4). This surveillance is performed in accordance with the guidance provided in the ESF RESPONSE TIME surveillance requirement in LCO 3.3.2, ESFAS.

REFERENCES

1. 10 CFR 50.67.
2. Not used.
3. Not used.
4. FSAR Table 7.3-16

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Filtration/Pressurization 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 Computer Room Ventilation System provides fresh outside air to the control room ventilation. Upon receipt of an actuation signal, the CREFS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Emergency Filtration/Pressurization System."

The actuation instrumentation consists of redundant radiation monitors in the air intake. A high radiation signal from one of these detectors will isolate the control room ventilation. The control room operator can initiate CREFS trains by manual switches in the control room. The CREFS is automatically actuated by a Phase A Containment isolation signal which also isolates the control room ventilation. 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 automatic actuation of CREFS acts to terminate the supply of unfiltered outside air to the control room, initiate filtration, and pressurize the control room. 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.

In MODES 1, 2, 3, and 4, the Phase A signal actuation ensures initiation of the CREFS during a loss of coolant accident or steam generator tube rupture. The automatic isolation of the control room ventilation by the radiation detectors provides backup protection for the control room but requires manual initiation of the CREFS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The radiation monitor actuation of control room isolation during movement of irradiated fuel assemblies, and CORE ALTERATIONS, alerts the operators to the need for manual initiation of the CREFS which will ensure control room habitability in the event of a fuel handling accident.

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 trains of manual initiation OPERABLE in MODES 1-4 and during CORE ALTERATIONS or movement of irradiated fuel assemblies. Two different methods of manual initiation are available to meet the requirements of this LCO, either method of manual initiation will accomplish the isolation of the control room and initiation of CREFS. Plant conditions and equipment availability vary through different MODES of operation and will affect which method of manual initiation may be used to meet the requirements of this LCO. The Phase A Containment Isolation manual switches (1 per train) provide a system level control room isolation and CREFS initiation to ensure the habitability of the control room, but Phase A Containment Isolation is only required OPERABLE by LCO 3.3.2, ESFAS Instrumentation, in MODES 1-4, and normally will not be available in MODES 5 and 6. When the system level manual Phase A initiation is not available, the manual switches for the individual CREFS recirculation and pressurization fans (2 handswitches per train) and the manual switches for the control room isolation valves (4 handswitches per train) also provide 2 trains of manual initiation capability to ensure the habitability of the control room. Either method may be used, as permitted by plant conditions and equipment availability, to meet the LCO requirement for two trains of manual initiation.

   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.

(continued)

BASES

LCO (continued)

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 the same features and operate in the same manner as described for ESFAS Function 3.a.2, Containment Isolation-Phase A, in LCO 3.3.2. The Actions Conditions for the CREFS portion of these Functions are different and less restrictive than those specified for their Phase A Isolation roles. If one or more of the Phase A Isolation Functions becomes inoperable in such a manner that only the CREFS Function is affected, the Conditions applicable to their Phase A Isolation Function need not be entered. The less restrictive Actions specified for inoperability of the CREFS Functions specify sufficient compensatory measures for this case.

3. Control Room Radiation

The LCO specifies one required Control Room Air Intake Radiation Monitor in MODES 1-4 to ensure that the radiation monitoring instrumentation necessary to provide a backup initiation of control room isolation remains OPERABLE. The LCO requires two air intake radiation monitor channels OPERABLE during CORE ALTERATIONS and during movement of irradiated fuel assemblies when the radiation monitor channels provide the primary control room protection function.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY also requires correct valve lineups and sample pump operation, as well as detector OPERABILITY.

4. Containment Isolation-Phase A

Refer to LCO 3.3.2, Function 3.a, for all initiating Functions and requirements except as described above in item 2, "Automatic Actuation Logic and Actuation Relays."

BASES

APPLICABILITY

The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, and the radiation monitor and manual initiation Functions must also be OPERABLE during CORE ALTERATIONS and movement of irradiated fuel assemblies to ensure a habitable environment for the control room operators. The Applicability for the CREFS actuation on the ESFAS Containment Isolation-Phase A Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for 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 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

Condition A applies to the actuation logic train Function of the CREFS, the radiation monitor channel Functions, and the manual channel Functions.

If one train is inoperable, or one required 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

(continued)

BASES

ACTIONS

A.1 (continued)

OPERABLE status, one 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.

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

Condition B applies to the failure of two CREFS actuation trains, two required radiation monitor channels, or two manual initiation trains. 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 the CREFS train made inoperable by the inoperable actuation instrumentation. In the case of inoperable radiation monitors, one train of CREFS must be declared inoperable and the applicable Condition of LCO 3.7.10 entered. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

Alternatively, both trains may be placed in the emergency recirculation mode. This ensures the CREFS function is performed even in the presence of a single failure.

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. Condition C is only applicable to those CREFS functions in Table 3.3.7-1 required OPERABLE in MODES 1-4. The unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 1). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 1, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met during CORE ALTERATIONS or when irradiated fuel assemblies are being moved. Condition D is only applicable to those CREFS functions in Table 3.3.7-1 required OPERABLE during CORE ALTERATIONS or during movement of irradiated fuel assemblies. Movement of irradiated fuel assemblies and CORE ALTERATIONS must be suspended immediately to reduce the risk of accidents that would require CREFS actuation or control room isolation.

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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.2

A COT is performed 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 actuation function. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3

SR 3.3.7.3 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.4

SR 3.3.7.4 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.3.7.5

SR 3.3.7.5 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 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 the slave relay. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. The test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.7

The 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.3 INSTRUMENTATION

B 3.3.8 Penetration Room Filtration (PRF) System Actuation Instrumentation

BASES

BACKGROUND

The PRF ensures that radioactive materials in the Spent Fuel Pool Room atmosphere following a fuel handling accident or ECCS pump rooms and penetration rooms of the auxiliary building following a loss of coolant accident (LOCA) are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.12, "Penetration Room Filtration System." The system initiates filtered ventilation of the Spent Fuel Pool Room (including isolation of the normal ventilation) automatically following receipt of a high radiation signal (gaseous) or a low air flow signal from the normal Spent Fuel Pool Room ventilation system. In addition, the system initiates filtered ventilation of the ECCS pump rooms and penetration rooms following receipt of a Phase B Containment Isolation signal. Initiation may also be performed manually as needed from the main control room.

High gaseous radiation provides PRF initiation. Each PRF train is initiated by high radiation detected by a channel dedicated to that train. There are a total of two channels, one for each train. Each channel contains a gaseous monitor. High radiation detected by either monitor or a low air flow signal from the normal Spent Fuel Pool Room ventilation or a Phase B Containment Isolation signal from the Engineered Safety Features Actuation System (ESFAS) starts the PRF. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the Spent Fuel Pool Room or ECCS pump rooms and penetration rooms. Since the radiation monitors include an air sampling system, various components such as sample line valves and sample pumps are required to support monitor OPERABILITY.

APPLICABLE SAFETY ANALYSES

The PRF ensures that radioactive materials in the Spent Fuel Pool Room atmosphere following a fuel handling accident or ECCS pump rooms and penetration rooms following a LOCA are filtered and adsorbed prior to being exhausted to the environment. This action reduces the radioactive content in the plant exhaust following a LOCA or fuel handling accident so that offsite doses remain within the limits specified in 10 CFR 50.67 (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

LCO

The LCO requirements ensure that instrumentation necessary to initiate the PRF is OPERABLE.

1. Manual Initiation

The LCO requires two trains OPERABLE. Each train consists of 2 handswitches for the PRF ventilation fans and one handswitch for the penetration room suction damper. The operator can initiate a PRF train at any time by using two fan switches and one damper switch 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 Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each train consists of two fan handswitches and one damper handswitch and the interconnecting wiring to the PRF fans and damper.

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 the same features and operate in the same manner as described for ESFAS Function 3.b.2, Phase B Containment Isolation, in LCO 3.3.2. The ACTIONS Conditions for the PRF portion of these functions are different and less restrictive than those specified for their Phase B roles. If one or more of the Phase B functions becomes inoperable in such a manner that only the PRF function is affected, the Conditions applicable to their Phase B function need not be entered. The less restrictive Actions specified for inoperability of the PRF functions specify sufficient compensatory measures for this case.

(continued)

BASES

LCO (continued)

3. Spent Fuel Pool Room Radiation

The LCO specifies two required Gaseous Radiation Monitor channels to ensure that the radiation monitoring instrumentation necessary to initiate the PRF remains OPERABLE. Each monitor will initiate the associated train of PRF and isolate the normal Spent Fuel Pool Room ventilation.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY requires correct valve lineups, sample pump operation, and detector OPERABILITY.

4. Spent Fuel Pool Room Ventilation Differential Pressure

The LCO specifies two channels of spent fuel pool room ventilation differential pressure instrumentation to assure filtration protection is provided when insufficient normal spent fuel pool room ventilation system flow exists to ensure proper operation of the radiation monitors. When the instrumentation detects insufficient spent fuel pool room ventilation flow, the PRF is actuated and the spent fuel storage pool room ventilation isolated in the same manner as the radiation monitor actuation of the system. The differential pressure instrumentation assures filtration of the spent fuel pool room exhaust when the spent fuel pool room normal ventilation system flow is not sufficient for proper operation of the radiation monitors.

5. Containment Isolation – Phase B

Refer to LCO 3.3.2, Function 3.b for all initiation Functions and requirements except as described above in item 2, "Automatic Actuation Logic and Actuation Relays."

Only the Trip Setpoint is specified for each PRF Function in the LCO. The Trip Setpoint limits are defined in plant procedures (Ref. 2).

APPLICABILITY

The manual PRF initiation must be OPERABLE in MODES 1, 2, 3, and 4 and when moving irradiated fuel assemblies in the Spent Fuel Pool Room, to ensure the PRF operates to remove fission products

(continued)

BASES

APPLICABILITY (continued)

associated with leakage after a LOCA or a fuel handling accident. The automatic Phase B PRF actuation instrumentation is also required in MODES 1, 2, 3, and 4 to remove fission products caused by post LOCA Emergency Core Cooling Systems leakage.

High radiation and the normal Spent Fuel Pool Room ventilation system low flow signal initiation of the PRF must be OPERABLE in any MODE during movement of irradiated fuel assemblies in the Spent Fuel Pool Room to ensure automatic initiation of the PRF when the potential for a fuel handling accident exists.

While in MODES 5 and 6 without fuel handling in progress, the PRF instrumentation need not be OPERABLE since a fuel handling accident cannot occur.

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. 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 to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.8-1 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

Condition A applies to the actuation logic train function of the Solid State Protection System (SSPS), the radiation monitor function, the Spent Fuel Pool Room differential pressure function, and the manual function. Condition A applies to the failure of a single actuation logic

(continued)

BASES

ACTIONS

A.1 (continued)

train, radiation monitor channel, Spent Fuel Pool Room differential pressure channel, or manual train. If one channel or train is inoperable, a period of 7 days is allowed to restore it to OPERABLE status. If the train cannot be restored to OPERABLE status, one PRF train must be placed in operation. This accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation. 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 time is the same as that provided in LCO 3.7.12.

B.1.1, B.1.2, B.2

Condition B applies to the failure of two PRF actuation logic trains, two radiation monitors, two Spent Fuel Pool Room differential pressure channels, or two manual trains. The Required Action is to place one PRF train in 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 3.7.12 must also be entered for the PRF train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed on train inoperability as discussed in the Bases for LCO 3.7.12.

Alternatively, both trains may be placed in operation. This ensures the PRF Function is performed even in the presence of a single failure.

C.1

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and irradiated fuel assemblies are being moved in the Spent Fuel Pool Room. Movement of irradiated fuel assemblies in the Spent Fuel Pool Room must be suspended immediately to eliminate the potential for events that could require PRF actuation.

This Condition is modified by a Note which limits the applicability of this Condition to those Functions on Table 3.3.8-1 required OPERABLE during movement of irradiated fuel assemblies in the spent fuel pool room to mitigate the consequences of a fuel handling accident. This Condition does not apply to Functions which are only

(continued)

BASES

ACTIONS

C.1 (continued)

required to mitigate the consequences of a LOCA (Phase B Isolation and associated automatic actuation logic and actuation relays). These Functions are not required OPERABLE when moving irradiated fuel assemblies and are unrelated to the mitigation of a fuel handling accident in the spent fuel pool room.

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 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.

This Condition is modified by a Note which limits the applicability of this Condition to those Functions on Table 3.3.8-1 required OPERABLE during MODES 1, 2, 3, or 4 to mitigate the consequences of a LOCA. This Condition is not intended to be applied to Functions which are only required to mitigate the consequences of a fuel handling accident in the Spent Fuel Pool Room (radiation monitors and Spent Fuel Pool Room normal ventilation differential pressure). These Functions are only required OPERABLE when moving irradiated fuel assemblies in the Spent Fuel Pool Room and are unrelated to the mitigation of the consequences of a LOCA.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which PRF Actuation Functions.

SR 3.3.8.1

Performance of the CHANNEL CHECK 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2

A COT is performed 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 PRF actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.3

SR 3.3.8.3 is the performance of an ACTUATION LOGIC TEST. All possible logic combinations, with and without applicable permissives, are tested for each protection function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.4

SR 3.3.8.4 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.5

SR 3.3.8.5 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 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 the slave relay. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.6

SR 3.3.8.6 is the performance of a TADOT. This test is a check of the manual and Spent Fuel Pool Room ventilation Differential Pressure actuation functions. The test includes actuation of the end device (e.g., pump starts, valve cycles, etc.). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no required setpoints associated with them.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.7

The 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67.
2. FNP – 1/2 - RCP - 252.
3. Not used.

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. The indicated limit is based on the average of two control board readings. 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. The indicated limit is based on the average of two control board readings. 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. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

APPLICABLE SAFETY ANALYSES

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 DNB design criterion throughout

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

each analyzed transient. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "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 analytical limits used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(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. Operating within these limits will result in meeting the DNB design criterion in the event of a DNB limited transient.

RCS total flow rate is based on two elbow tap measurements from each loop and contains a measurement error of 2.3% based on Δp measurements from the cold leg elbow taps, which are correlated to past precision heat balance measurements or performing a precision heat balance at the beginning of the current cycle. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner. Therefore, a penalty of 0.1% for undetected fouling of the feedwater venturi raises the nominal flow measurement allowance to 2.4%.

Any fouling that might bias the flow rate measurement greater than 0.1% can be detected by monitoring and trending various plant performance parameters. If detected, action shall be taken before performing subsequent precision heat balance measurements, i.e., 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.

BASES

APPLICABILITY

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 > 5% RTP per minute or a THERMAL POWER step > 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 on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." The conditions that 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 eliminate the potential for violation of the accident analysis bounds.

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

(continued)

BASES

ACTIONS (continued)

B.1

If Required Action A.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.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.3

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4

The surveillance of the total RCS flow rate may be performed by one of two alternate methods. One method is a precision calorimetric as documented in WCAP-12771, Rev. 1. The other method is based on the Δp measurements from the cold leg elbow taps, which are correlated to past precision heat balance measurements. Correlation of the flow indication channels with selected precision loop flow calorimetrics for this method is documented in WCAP-14750. Use of the elbow tap Δp measurement method removes the requirement for performance of a precision RCS flow calorimetric measurement.

Measurement of RCS total flow rate by performance of one of these two methods verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 7 days after ≥ 90% RTP. This exception is appropriate since the heat balance and elbow tap measurement methods both require the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 7 days after reaching 90% RTP. The intent is that this Surveillance be performed near the beginning of the cycle as close as possible to 100% RTP.

REFERENCES

1. FSAR, Section 4.4 and 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical 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 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a 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.

BASES

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 3 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 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be periodically verified at or above 541°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 4.3 and 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 (Ref. 1).

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 XI, 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

(continued)

BASES

BACKGROUND (continued)

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).

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(c)(2)(ii).

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.

BASES

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. 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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 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.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. WCAP-14040-A, Revision 4, May 2004.
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section XI, 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 three 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming three RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the complete loss of forced reactor coolant flow, single RCP locked rotor, partial loss of reactor coolant flow (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the three RCS loop operation. For three RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 120% RTP. This is the design overpower condition for three RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 118% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, 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 10 CFR 50.36(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, three pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

BASES

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.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "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.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.4.4.1</u> This SR requires verification that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Sections 15.2.2, 15.2.5, 15.3.4, 15.3.6, 15.4.4.3, and 15.4.6.3.

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 three 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.

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 the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops — MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two OPERABLE RCS loops must be in operation. Two OPERABLE 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 OPERABLE 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 safety analyses limits are met.

The Note permits all RCPs to not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. 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 a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow.

(continued)

BASES

LCO
(continued)

The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction 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.

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. This assumes steam removal capability and the availability of a makeup water source (if necessary for extended use of the SG) as required to remove decay heat. 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 the 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.

(continued)

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "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.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal.

The Completion Time of 1 hour to restore the required RCS loop to operation or defeat the Rod Control System 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 two required 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 a reduction of RCS boron concentration 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. 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 that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 ≥ 30% for required RCS loops. If the SG

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

secondary side narrow range water level is < 30%, 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 three 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 have been identified in the NRC Policy Statement as important contributors to risk reduction.

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

(continued)

BASES

LCO (continued)

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 not be in operation for ≤ 2 hours per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 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.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction 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 requires that the secondary side water temperature of each SG be < 50°F above each of the RCS cold leg temperatures or that the pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication) before the start of an RCP with any RCS cold leg temperature ≤ the Low Temperature Overpressure Protection (LTOP) System applicability temperature specified in the PTLR. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

(continued)

BASES

LCO (continued)

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. This assumes steam removal capability and the availability of a makeup water source (if necessary for extended use of the SG) as required to remove decay heat.

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. Management of gas voids is important to RHR System OPERABILITY.

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.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable and two RHR loops are 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.

(continued)

BASES

ACTIONS (continued)

B.1

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.

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration 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 criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 wide range water level is ≥ 75%. If the SG secondary side wide range water level is < 75%, 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.4 (continued)

at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note 1 that states the SR is not required to be performed until 12 hours after entering MODE 4. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering MODE 4.

This SR is modified by a Note 2 clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.6.4 (continued) flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.
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 this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) 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 via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot 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.

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.

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 ≥ 75% (wide range) to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

BASES

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.

RCS Loops — MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

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 ≥ 75% (wide range). 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 ≥ 75% (wide range). 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 not be in operation ≤ 2 hours per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 2 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 initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration

(continued)

BASES

LCO (continued)

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.

Note 3 requires that the secondary side water temperature of each SG be < 50°F above each of the RCS cold leg temperatures or that the pressurizer water volume is less than 770 cubic feet (24% of wide range, cold, pressurizer level indication) before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ the Low Temperature Overpressure Protection (LTOP) System applicability temperature specified in the PTLR. 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.

Note 5 restricts the number of operating reactor coolant pumps at RCS temperatures less than 110°F. Only one reactor coolant pump is allowed to be in operation below 110°F (except during pump swap operations) consistent with the assumptions of the P/T Limits Curve.

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. Management of gas voids is important to RHR System OPERABILITY.

(continued)

BASES

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 ≥ 75% (wide range).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "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 < 75% (wide range), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to 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 Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ 75% 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 ≥ 75% (wide range) in at least two SGs, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.4 (continued)

the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.4 (continued)

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

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) have been identified in the NRC Policy Statement as important contributors to risk reduction.

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.

(continued)

BASES

LCO (continued)

Note 1 permits all RHR pumps to not be in operation for ≤ 15 minutes when switching from one loop to another. 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 > 10°F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

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. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

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

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "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 a reduction of RCS boron concentration 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. 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 that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.8-3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.3 (continued)

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.3 (continued)

The RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

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.

BASES

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 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 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 868 cubic feet, which is equivalent to 63.5% indicated, 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 ≥ 125 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. The exact design value of 125 kW is derived from the use of seven heaters rated at 17.9 kW each. The amount needed to maintain pressure is dependent on the heat losses.

BASES

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.

A Note has been added to indicate the limit on pressurizer level is not applicable during short term operational transients such as a THERMAL POWER ramp > 5% RTP per minute or a THERMAL POWER step > 10% RTP. These conditions represent short term perturbations.

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

ACTIONS

A.1, A.2, A3 and A4

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.

If the pressurizer water level is not within the limit, when the limit is applicable, 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. 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.

(continued)

BASES

ACTIONS (continued)

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 caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

C.1 and C.2

If one group of pressurizer heaters are 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, 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.2

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 measuring circuit current or testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.4.9.3 This Surveillance demonstrates that the heaters can be manually transferred from the normal to the emergency power supply and energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Sections 15.1, 15.2, and 6.2. 2. NUREG-0737, November 1980.

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, 345,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety 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 ≤ the Low Temperature Overpressure Protection (LTOP) System applicability temperature specified in the PTLR, 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 ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the

(continued)

BASES

BACKGROUND (continued)

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. Loss of reactor coolant flow;

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 in events c, d, and e (above) 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 10 CFR 50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2500 psia), 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

(continued)

BASES

LCO (continued)

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 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 when all RCS cold leg temperatures are > the LTOP System applicability temperature specified in the PTLR, 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 one or more RCS cold leg temperatures are ≤ the LTOP System applicability temperature specified in the PTLR or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

Normally demonstration of the safety valves' lift settings will occur during shutdown and will be performed in accordance with the provisions of the ASME Code for Operation and Maintenance of Nuclear Power Plants.

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 timeframe.

BASES

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 ≤ the LTOP System applicability temperature specified in the PTLR 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. With any RCS cold leg temperatures at or below the LTOP System applicability temperature specified in the PTLR, 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

Pressurizer safety valves are to be tested in accordance with the requirements of the ASME OM Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 1% for OPERABILITY.

BASES

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.

2. FSAR, Chapter 5.2, 5.5, 15.2, 15.3 and 15.4.

3. WCAP-7769, Rev. 1, June 1972.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

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 air 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 design relief capacity of 210,000 lb/hr at 2485 psig with a set pressure of 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure — High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves.

BASES

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.

For the Inadvertent Operation of ECCS During Power Operation event, the safety analysis assumes that manual operator actions are required to mitigate the event. At least one PORV is assumed to be unblocked and available for water relief prior to reaching a water-solid condition. Use of at least one PORV precludes subcooled water relief through the Pressurizer Safety Relief Valves (PSRVs) by depressurinzing the RCS below the pressure where the PSRVs reseat. Should water relief through the PORV(s) occur, the PORV block valve(s) would be available to isolate the RCS.

The PORVs are used in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical. By assuming PORV manual actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. Events that assume this condition include a loss of RCS flow and a turbine trip (Ref. 2).

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(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 or an inadvertent operation of ECCS during power operation event.

The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

(continued)

BASES

LCO (continued)

A. Manual control of PORVs to control reactor coolant system pressure. This is a function that is used for the steam generator tube rupture accident, the inadvertent operation of ECCS during power operation event, and for plant shutdown.

B. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

C. Manual control of the block valve to: (1) unblock an isolated PORV to allow it to be used for manual control of reactor coolant system pressure (Item A), and (2) isolate a PORV with excessive seat leakage (Item B).

D. Manual control of a block valve to isolate a stuck-open PORV.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. The block valves are available to isolate the flow path through either a failed open PORV or a PORV with excessive leakage. 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 to minimize challenges to the pressurizer safety valves.

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 MODE 4 when both pressure and core energy are decreased and the pressure surges become much less significant. The RHR relief

(continued)

BASES

APPLICABILITY (continued)

valves or an RCS vent of ≥ 2.85 inches squared is used for overpressure protection in MODES 4, 5, and 6 with the reactor vessel head in place. LCO 3.4.12 addresses the overpressure protection requirements in these MODES.

ACTIONS

A Note has been added to clarify that all pressurizer PORVs and block valves are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

With the PORVs inoperable and capable of being manually cycled, either the PORVs must be restored or the flow path isolated within 1 hour. The block valves should be closed but power must be maintained to the associated block valves, since removal of power would render the block valve inoperable. Although a PORV may be designated inoperable, it may be able to be manually opened and closed, and therefore, able to perform its function. PORV inoperability may be due to seat leakage, instrumentation problems related to remote manual operation of the PORVs, or other causes that do not prevent manual use and do not create a possibility for a small break LOCA. For these reasons, the block valve may be closed but the Action requires power be maintained to the valve. This Condition is only intended to permit operation of the plant for a limited period of time not to exceed 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 are not capable of mitigating an overpressure event when placed in manual control. 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.

(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, the PORVs are not required OPERABLE.

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 one PORV is restored and one PORV remains inoperable, then the plant will be in Condition B with the time clock started at the original declaration of having two PORVs inoperable. 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, the PORVs are not required OPERABLE.

F.1 and F.2

If two block valves are inoperable, it is necessary to restore at least one block valve 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.

(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, the PORVs are not required OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be closed if needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 test to be performed in MODE 3 under operating temperature conditions, prior to entering MODE 1 or 2. In accordance with Reference 3, administrative controls require this test to be performed in MODE 3 or 4 to adequately simulate opening temperature and pressure effects on PORV operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV in MODE 3 or 4. The PORVs are stroke tested during MODES 3 or 4 with the associated block valves closed in order to limit the uncertainty introduced by testing the PORVs at lesser system temperatures than expected during actual operating conditions. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Note modifies this SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature conditions, prior to entering MODE 1 or 2.

SR 3.4.11.3

SR 3.4.11.3 requires a complete cycle of each PORV using the backup PORV control system. This surveillance verifies the capability to operate the PORVs using the backup nitrogen supply system. Additionally, this surveillance ensures the correct function of the associated nitrogen supply system valves. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.32, February 1977.

2. FSAR Sections 5.5 and 15.2.

3. 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 Protection for Light-Water Reactors,’ Pursuant to 10 CFR 50.54(f),” June 25, 1990.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (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. This Technical Specification provides the maximum allowable actuation setpoints for the RHR relief valves and the PTLR contains 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. In addition, the PTLR contains the LTOP System MODE 4 applicability temperature.

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:

a. A maximum of one charging pump capable of injecting into the RCS when one or more RCS cold leg temperatures are ≤ 180°F;

b. A maximum of two charging pumps capable of injecting into the RCS when all the RCS cold leg temperatures are > 180°F; and

(continued)

BASES

BACKGROUND (continued)

c. Isolating the accumulators.

The pressure relief capacity requires either two redundant RHR relief valves or a depressurized RCS and an RCS vent of sufficient size. One RHR 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 one charging pump 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 residual heat removal (RHR) suction relief valves, or a depressurized RCS and an RCS vent of sufficient size. Two RHR relief valves are required for redundancy. One RHR relief valve has adequate relieving capability to keep from overpressurization for the required coolant input capability.

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 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 and the RHR suction 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. Each relief valve has the capacity to mitigate overpressurization in the worst case of inadvertent startup of three charging pumps injecting into a solid RCS.

(continued)

BASES

BACKGROUND (continued)

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. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 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 all RCS cold leg temperatures exceeding the LTOP System applicability temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. With one or more RCS cold leg temperatures ≤ the LTOP System applicability temperature specified in the PTLR, overpressure prevention falls to two OPERABLE RHR 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 RHR 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 Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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. A maximum of one charging pump capable of injecting into the RCS when one or more RCS cold leg temperatures are ≤ 180°F and a maximum of two charging pumps capable of injecting into the RCS when all the RCS cold leg temperatures are > 180°F.

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop except as provided for in LCO 3.4.6, "RCS Loops — MODE 4," and LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled."

In the Reference 4 analyses, the worst case mass input event was assumed to be the inadvertent operation of three high-head safety injection pumps (i.e., charging pumps) with a maximum total flowrate of 1000 gal/min at 0 psig backpressure at RCS temperatures ≥ 180°F. The analysis conservatively assumes the operation of three charging pumps although the plant design limits the total number of operating charging pumps to two pumps at a time. Additionally, Reference 4 states that due to the Technical Specification restrictions that allow only one charging pump capable of injecting into the RCS at RCS temperatures < 180°F, the worst case mass injection is limited to the start of a single charging pump. Since one RHR relief valve has not

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Heat Input Type Transients (continued)

been demonstrated to be able to handle the pressure transient need from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators isolated 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 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 for the LTOP System Applicability specified in the PTLR.

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 one charging pump OPERABLE at RCS temperatures ≤ 180°F and SI actuation enabled.

RHR Suction Relief Valve Performance

The RHR suction relief valves do not have variable pressure and temperature lift setpoints like the PORVs. Analyses show that one RHR suction relief valve (2.85 square inch throat) with a setpoint ≤ 450 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.

Although each RHR suction relief valve may itself meet single failure criteria, its inclusion and location within the RHR System does not allow it to meet single failure criteria when spurious RHR suction isolation valve closure is postulated. Also, as 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 considered active components. Thus, the failure of one valve is assumed to represent the worst case single active failure.

The RHR suction relief valves are considered active components. Thus, the failure of one valve is assumed to represent the worst case single active failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RCS Vent Performance

With the RCS depressurized, analyses show a vent equivalent to an RHR relief valve is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, one charging pump 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 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are 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 the following:

a. A maximum of one charging pump capable of injecting into the RCS when one or more RCS cold leg temperatures are ≤ 180°F;

b. A maximum of two charging pumps capable of injecting into the RCS when all the RCS cold leg temperatures are > 180°F; and

c. All accumulator discharge isolation valves 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.

(continued)

BASES

LCO (continued)

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE RHR suction relief valves; or

   An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valve and its RHR suction valve are open, its setpoint is ≤ 450 psig, and testing has proven its ability to open at this setpoint.

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 2.85 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The LCO is modified by two Notes. Note 1 allows for two charging pumps to be capable of injecting into the RCS during pump swap operations, when one or more of the RCS cold legs is ≤ 180°F, for a period of no more than 15 minutes provided that the RCS is in a non-water solid condition and both RHR relief valves are OPERABLE or the RCS is vented via an opening of no less than 5.7 square inches in area. A 5.7 square inch opening is equivalent to the throat size area of two RHR relief valves. This allows seal injection flow to be continually maintained, thus minimizing the potential for RCP number one seal damage by reducing pressure transients on the seal and by preventing RCS water from entering the seal. Particles in the RCS water may cause wear on the seal surfaces and loss of seal injection pressure may cause the seal not to fully reseat when pressure is reapplied. Note 2 states that accumulator isolation is only required when the accumulator pressure is more than or at 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.

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ the LTOP System applicability temperature specified in the PTLR, in MODE 5, and in MODE 6 when the reactor vessel head is on (i.e., fully seated on the reactor vessel flange, with or

(continued)

BASES

APPLICABILITY (continued)

without studs). The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits when all the RCS cold leg temperatures are > the LTOP System applicability temperature specified in the PTLR. When the reactor vessel head is raised, such that a total vent area of ≥ 2.85 square inches is created, seated on blocks providing an equivalent vent area, or 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 when all the RCS cold leg temperatures are > the LTOP System applicability temperature specified in the PTLR.

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 with little or no time allowed for operator action to mitigate the event.

ACTIONS

A Note prohibits the application of LCO 3.0.4b to an inoperable LTOP system when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4b, 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.

<u>A.1</u>

With more than the maximum required 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.

(continued)

BASES

ACTIONS (continued)

B.1, C.1, and C.2

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 C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature in all the cold legs to > the LTOP System applicability temperature specified in the PTLR, an accumulator pressure of 600-650 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.

D.1, D.2, and D.3

In MODE 4 when any RCS cold leg temperature is ≤ the LTOP System applicability temperature specified in the PTLR, with one required RHR relief valve inoperable, the pressurizer level must be reduced to ≤ 30% (cold calibrated) and a dedicated operator must be assigned for RCS pressure monitoring and control within 24 hours. These actions provide additional assurance that an RCS pressure transient will be rapidly identified and operator action taken to limit the transient. The RHR relief valve must be restored to OPERABLE status within a Completion Time of 7 days. Two RHR relief valves are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The 7 day Completion Time considers the facts that only one of the RHR relief valves is required to mitigate an overpressure transient, the actions taken to reduce pressurizer level and monitor RCS pressure, and that the likelihood of an active failure of the remaining valve path during this time period is very low.

(continued)

BASES

ACTIONS (continued)

E.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RHR relief valves are inoperable; or

b. A Required Action and associated Completion Time of Condition A, C, or D is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, or D.

The vent must be sized ≥ 2.85 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.

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, the following are required:

a. A maximum of one charging pump capable of injecting into the RCS when one or more RCS cold leg temperatures are ≤ 180°F;

b. A maximum of two charging pumps capable of injecting into the RCS when all the RCS cold leg temperatures are > 180°F; and

c. The accumulator discharge isolation valves are verified closed and locked out.

The charging pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 (continued)

pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the Hot Shutdown Panel Local/Remote and pump control switches being placed in the Local and Stop positions, respectively, and at least one valve in the discharge flow path being closed with the position of these components controlled administratively.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.4

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying its RHR suction isolation valves (8701A, 8701B, 8702A and 8702B) are open. This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.5

The RCS vent of ≥ 2.85 square inches is proven OPERABLE by verifying its open condition.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12b.

SR 3.4.12.6

The RHR relief valves are verified OPERABLE by testing the relief setpoint. The setpoint verification ensures proper relief valve mechanical motion as well as verifying the setpoint. Testing is performed in accordance with the INSERVICE TESTING PROGRAM which is based on the requirements of the ASME OM Code (Ref. 7).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.6 (continued)

The RHR relief valve setpoints are verified in accordance with the Surveillance Frequency Control Program. Per the INSERVICE TESTING PROGRAM, if the scheduled valve exceeds the relief setpoint by 3% or greater, the remaining valve shall also be tested. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. ASME, Boiler and Pressure Vessel Code, Section III.
4. FSAR, Chapter 5.2.2.4.
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

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

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. 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.

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 being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is typically seen as a precursor to a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gpm 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 gpd (i.e. total leakage less than or equal to 450 gpd) is significantly less than the conditions assumed in the safety analysis (with leakage assumed to occur at room temperature in both cases).

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

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture. Therefore, the 1 gpm primary to secondary LEAKAGE safety analysis assumption is relatively inconsequential.

The MSLB is more limiting for primary to secondary LEAKAGE. The safety analysis for the MSLB assumes 0.35 gpm and 0.65 gpm primary to secondary LEAKAGE in the faulted and both intact steam generators respectively as an initial condition (1 gpm total). The offsite dose consequences resulting from the MSLB accident are bounded by a small fraction (i.e., 10%) of the limits defined in 10 CFR 50.67. The RCS specific activity assumed was 0.5 μCi/gm DOSE EQUIVALENT I-131 at a conservatively high letdown flow of 145 gpm, with either a pre-existing or an accident initiated iodine spike. These values bound the Technical Specifications values.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

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.

b. Unidentified LEAKAGE

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

c. Identified LEAKAGE

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

d. Primary to Secondary LEAKAGE Through Any One SG

The limit of 150 gpd per each SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, “The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day.” The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

BASES

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 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 4 within 12 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 4, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 6). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 6, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. 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 and near operating pressure. The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed in MODES 3 and 4 until 12 hours of steady state operation near operating pressure have been established.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP 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 air cooler condensate flow rate. 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. This is because LEAKAGE of 150 gpd cannot be measured accurately by an RCS water inventory balance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gpd through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17, “Steam Generator Tube Integrity,” should be evaluated. The 150 gpd limit is measured at room temperature as described in Reference 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.2 (continued)

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 is controlled under the Surveillance Frequency Control Program. During normal operation the primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with EPRI guidelines.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 3.1.2.6, 5.2.7, 10.4, 11.0, 12.0 and 15.0.
4. NEI 97-06, “Steam Generator Program Guidelines.”
5. EPRI TR-104788, “Pressurized Water Reactor Primary-to-Secondary Leak Guidelines.”
6. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

(continued)

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 must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual 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.

(continued)

BASES

BACKGROUND (continued)

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

a. Residual Heat Removal (RHR) System; and

b. Charging System.

The PIVs are listed in the Technical Requirements Manual (TRM) (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 10 CFR 50.36(c)(2)(ii).

LCO

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

(continued)

BASES

LCO (continued)

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 3 or 5 gpm depending on the valve. The previous NRC Standard criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

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.

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.

(continued)

BASES

ACTIONS (continued)

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. However, the valves used to isolate the flow path (which are not PIVs) do not have to be pre-qualified by periodic testing. When Required Action A is entered and the flow path isolated, the valves will be verified at that time to meet the leakage requirements of SR 3.4.14.1. This is accomplished using the methodology of SR 3.4.13.1 (RCS water inventory balance) with the leakage limits of SR 3.4.14.1 applied.

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 one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 9). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 9, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.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 autoclosure interlock renders the associated RHR suction isolation valves incapable of isolating in response to a high pressure condition. The inoperability of the RHR open permissive interlock renders the associated RHR suction isolation valves incapable of preventing inadvertent opening of the valves at RCS pressures in excess of the RHR systems design pressure. If the RHR autoclosure or open permissive interlocks are inoperable, operation may continue as long as the affected RHR suction valves are closed and administrative controls are in place in the control room to maintain them closed (e.g., tags on the main control board handswitches, etc.) within 4 hours. This Action accomplishes the purpose of the autoclosure or open permissive function.

Required Action C.1 is modified by a Note that states the Required Action for the autoclosure interlock is not applicable to Unit 1 after 1R27 and not applicable to Unit 2 after 2R25. The Required Action for the autoclosure interlock is no longer applicable after these refueling outages because the autoclosure interlock will be removed during the outages and will no longer be required OPERABLE.

Note to Operators: After 1R27 (Unit 1) and 2R25 (Unit 2) when the RHR autoclosure interlocks are removed from each unit, the RHR suction isolation valves will be required to be closed with power removed from the valves in MODES 1, 2, and 3. The requirement to isolate the valves with power removed in these MODES is necessary to satisfy the conditions for removal of the RHR autoclosure interlock.

(continued)

BASES

ACTIONS

C.1 (continued)

If the open permissive interlock becomes inoperable after the removal of the autoclosure interlock, the Required Action to ensure the valves are closed using the administrative controls described above would only be applicable in MODE 4. In MODES 1, 2, and 3, if an open permissive interlock becomes inoperable, the Required Action to close and maintain close the valves by administrative controls would be met by the administrative controls in place to ensure the valves are closed with power removed (as required for the removal of the autoclosure interlock).

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. However, the valves used to isolate the flow path to satisfy Required Actions A.1 and A.2 (which are not PIVs) do not have to be pre-qualified by periodic testing. When Required Action A is entered and the flow path isolated, the valves will be verified at that time to meet the leakage requirements of SR 3.4.14.1.

This is accomplished using the methodology of SR 3.4.13.1 (RCS water inventory balance) with the leakage limits of SR 3.4.14.1 applied. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to a 3 or 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

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, on all PIVs listed in the TRM. 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) OM 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

In order to satisfy ALARA requirements, leakage may be measured indirectly (as from performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with leakage criteria.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating except for RCS PIVs located in the RHR flow path (Q1/2E11V001A and B, Q1/2E11V016A and B, Q1/2E11V021A, B, C and Q1/2E11V042A and B). PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed after the valve has been reseated.

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. 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 when RHR is secured and stable unit conditions and the necessary differential pressures are established. Leak rate testing is performed manually, with test personnel in the vicinity of the system connections in containment during setup and testing. Should the check valve that was being tested rupture or pressure in the system cause a rupture of the test equipment, there would be a concern for the safety of the personnel in the area. In addition, testing with RCS temperature above 212 °F would result in any leakage past the RHR valves flashing into steam making accurate measurement of the leakage rate impossible. Therefore, testing of the RHR System PIVs should normally be performed in Mode 5, as the test results are meaningful and plant conditions in Mode 5 minimize the potential impact on personnel safety.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.14.2

Verifying that the RHR autoclosure interlock is OPERABLE ensures that RCS pressure will not pressurize the RHR system beyond 125% of its design pressure of 600 psig. The autoclosure interlock isolates the RHR System from the RCS when the interlock setpoint is reached. The setpoint ensures the RHR design pressure will not be exceeded. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by two Notes. Note 1 provides an exception to the requirement to perform this surveillance when using the RHR System suction relief valves for cold overpressure protection in accordance with SR 3.4.12.3.

Note 2 states the Surveillance is not applicable to Unit 1 after 1R27 and not applicable to Unit 2 after 2R25. The Surveillance is no longer applicable after these refueling outages because the autoclosure interlock will be removed during the outages and will no longer be required OPERABLE.

SR 3.4.14.3

Verifying that the RHR open permissive interlock is OPERABLE ensures that the RCS will not pressurize the RHR system beyond design of 600 psig. The open permissive interlock prevents opening the RHR System suction valves from the RCS when the RCS pressure is above the setpoint. The setpoint upper value ensures the RHR System design pressure will not be exceeded at the RHR pump discharge and was chosen taking into account instrument uncertainty and calibration tolerances. This value also provides assurance that the RHR System suction relief valves setpoint will not be exceeded.

The minimum value of the setpoint range is chosen based upon operational considerations (differential pressure) for the RCP seals and thus does not have a safety-related function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that provides an exception to the requirement to perform this surveillance when using the RHR System suction relief valves for cold overpressure protection in accordance with SR 3.4.12.3.

BASES

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 Requirement Manual (TRM).
7. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
8. 10 CFR 50.55a(g).
9. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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, Revision 0 (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. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

The containment air cooler condensate level monitor is instrumented to alarm for abnormal increases in the level (flow rates). The condensate flow rate is measured by monitoring the water level in a vertical standpipe. As flow rate increases, the water level in the standpipe rises.

The reactor coolant contains radioactivity that, when released to the containment, may be detected by radiation monitoring instrumentation. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE. Other indications may be used to detect an increase in unidentified LEAKAGE; however, they are not required to be OPERABLE by this LCO.

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

(continued)

BASES

BACKGROUND (continued)

levels of the containment atmosphere as an indicator of potential RCS LEAKAGE.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow from the containment condensate 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 is affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

The above-mentioned LEAKAGE detection systems differ in sensitivity and response time. Some of these systems could serve as early alarm systems identifying to the operators that closer examination of other detection systems is necessary to determine the extent of any corrective action that may be required.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring 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 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires two instruments to be OPERABLE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by the gaseous or particulate containment atmosphere radioactivity monitor. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE, but have recognized limitations. Reactor coolant radioactivity levels will be low during the initial reactor startup following a refueling outage and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel assembly cladding contamination or cladding defects. If there are few fuel assembly cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting approximately a 1 gpm increase in unidentified LEAKAGE within approximately 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors as described in Reference 3.

An increase in humidity of the containment atmosphere could indicate the release of water vapor to the containment. The containment air cooler condensate level monitor detects condensate flow from air coolers by monitoring a standpipe level increase versus time. The time required to detect approximately a 1 gpm increase above the normal value varies based on environmental and system conditions and may take longer than 1 hour. This sensitivity is acceptable for containment air cooler condensate level monitor OPERABILITY.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment atmosphere particulate radioactivity monitor (R-11) in combination with a gaseous radioactivity monitor (R-12) or a containment air cooler condensate level monitor provides an acceptable minimum.

BASES

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.1.1, A.1.2, and A.2

With the required containment atmosphere particulate radioactivity monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere gaseous radioactivity monitor or the containment air cooler condensate level monitor will provide indications of changes in leakage. Together with the containment atmosphere gaseous radioactivity monitor or the containment air cooler condensate level monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours or grab samples of the containment atmosphere must be taken and analyzed once per 24 hours to provide information that is adequate to detect leakage.

Restoration of the required Particulate radioactivity monitor 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 or containment grab sample analyses required by Required Action A.1.1 or A.1.2.

(continued)

BASES

ACTIONS (continued)

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

With both the required gaseous containment atmosphere radioactivity monitoring instrumentation channel and the required containment air cooler condensate level 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 at least one of the required containment monitors.

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

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

With the required containment atmosphere particulate radioactivity monitor inoperable and the required containment air cooler condensate level monitor inoperable, the only means of detecting LEAKAGE is the required containment atmosphere gaseous radioactivity monitor. This Condition is applicable when the only OPERABLE monitor is the containment atmosphere gaseous radioactivity monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1 gpm leak within 1 hour when the RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the containment atmosphere must be taken to provide alternate periodic information. The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to restore the intended leakage detection diversity. The 7 day Completion time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

D.1 and D.2

If a Required Action of Condition A, B, or C cannot be met, the plant must be brought to a MODE in which overall plant risk is reduced.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1 (continued)

gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.3 and SR 3.4.15.4

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.

2. Regulatory Guide 1.45, Revision 0, “Reactor Coolant Pressure Boundary Leakage Detection Systems,” May 1973.

3. FSAR, Section 5.2.7.

4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose that an individual at the exclusion area boundary can receive for 2 hours during an accident, or for the duration of the accident at the Low Population Zone, is specified in 10 CFR 50.67 (Ref. 1). The limits on specific activity ensure that the doses are held to an appropriate fraction of the 10 CFR 50.67 limits (i.e., a small fraction of or well within the 10 CFR 50.67 limits depending on the specific accident analysis) 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 main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the exclusion area boundary, or at the low population zone outer boundary for the radiological release duration, to an appropriate fraction of the 10 CFR 50.67 dose limits.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting doses will not exceed an appropriate fraction of the 10 CFR 50.67 dose limits following a SGTR or MSLB accident. The SGTR and MSLB safety analyses (Ref. 2 and 3) assume the specific activity of the reactor coolant at 0.5 μCi/gm, a conservatively high letdown flow of 145 gpm, and a bounding reactor coolant steam generator (SG) tube leakage of 1 gpm total for three SGs. These analyses resulted in offsite doses bounded by a small fraction (i.e., 10%) of the 10 CFR 50.67 guidelines using FGR No. 11 and 12 Dose Conversion Factors (DCFs). The initial RCS specific activity assumed was 0.5 μCi/gm DOSE EQUIVALENT I-131 at a conservatively high letdown flow of 145 gpm with an iodine spike. These values bound the Technical Specifications values. The safety analysis assumes for both the SGTR and MSLB the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.16, "Secondary Specific Activity."

(continued)

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis for the SGTR and MSLB accident establishes the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The SGTR and MSLB analyses consider two cases of reactor coolant specific activity. One case assumes specific activity at 0.5 μCi/gm DOSE EQUIVALENT I-131 at a conservatively high letdown flow of 145 gpm with an accident initiated iodine spike that increases the I-131 activity release rate into the reactor coolant by a factor of 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 30 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. These values bound the Technical Specifications values. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The SGTR analysis also assumes a loss of offsite power coincident with a reactor trip. 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 ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends. The MSLB analysis assumes a double-ended guillotine break of a main steamline outside of containment. The affected steam generator will rapidly depressurize and release both the radionuclides initially contained in the secondary coolant, and the primary coolant activity transferred via SG tube leakage, directly to the outside atmosphere. A portion of the iodine activity initially contained in the intact SGs and noble gas activity due to SG tube leakage is released to the atmosphere through either the SG atmospheric relief valves (ARVs) or the SG safety relief valves.

The safety analysis assumes an accident initiated iodine spike and shows the radiological consequences of a MSLB accident are within a small fraction of the Reference 1 dose limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the pre-accident activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The MSLB safety analysis has pre-accident iodine spiking levels up to 30 μCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a MSLB accident occurring during the established 48 hour time limit. The occurrence of a MSLB accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 50.67 dose limits.

The limits on RCS specific activity are also used for establishing standardization in plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 0.5 μCi/gm DOSE EQUIVALENT I-131 at a conservatively high letdown flow of 145 gpm for the SGTR analysis and for the MSLB analysis, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the dose to an individual during the Design Basis Accident (DBA) will be an appropriate fraction of the allowed dose. The limit on gross specific activity ensures the 2 hour dose to an individual at the site boundary during the DBA will be a small fraction of the allowed dose. The SGTR (Ref. 2) and MSLB accident analyses show that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR or MSLB, lead to site boundary doses that exceed the dose limits.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an SGTR or MSLB to within the acceptable site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

BASES

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling 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 required, if the limit violation resulted from normal iodine spiking.

A Note permits the use of the provisions of LCO 3.0.4c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

With the gross specific activity in excess of the allowed limit, the unit must be placed in a MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. 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 fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

BASES

REFERENCES

1. 10 CFR 50.67.
2. FSAR, Section 15.4.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. SG 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.

SG tubing is subject to a variety of degradation mechanisms. SG 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.

(continued)

BASES

BACKGROUND (continued)

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to 1 gpm plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released via the main steam safety valves. The majority of the activity released to the atmosphere results from the tube rupture.

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 gpm 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 10 CFR 50.67 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

(continued)

BASES

LCO (continued)

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, “Steam Generator Program,” and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

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.” Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gallon per minute (gpm) total from all SGs. The accident

(continued)

BASES

LCO (continued)

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 gpd. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next 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 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the “as found” condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also 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. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 5.5.9 until subsequent inspections support extending the inspection interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.9 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 plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 and Reference 6 provide guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of "Prior to entering MODE 4 following a SG inspection" ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. Not used.

3. 10 CFR 50.67.

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 TR-107569, "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 accumulator motor operated isolation valves are maintained in the open position with power to the valve removed when pressurizer pressure is ≥ 2000 psig. Should the valves be inadvertently closed below 2000 psig, the requirements of this LCO would ensure that the valves would be returned to their correct position in a timely manner or the plant would be taken out of the Mode of Applicability. The valves will

(continued)

BASES

BACKGROUND (continued)

automatically open, however, as a result of an SI signal. These features and requirements ensure that the accumulators will be available for injection.

The accumulator size, water volume, and nitrogen cover pressure are selected so that two of the three accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that two 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. 1). 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 also considered to determine if it is most limiting, and if so, 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 in the cold leg. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 solely 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.

This LCO helps to ensure that the following acceptance criteria established for the ECCS 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 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 large breaks, an increase in water volume can 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 safety analysis assumes values of 7331 gallons for the accumulator, and 337 gallons for the accumulator discharge line. To allow for instrument inaccuracy, values of 7,555 gallons and 7,780 gallons are specified. These values include the volume of water in the accumulator discharge line.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure for small break LOCA and nominal nitrogen cover pressure for large break LOCA, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. A sensitivity study is performed for the BE LOCA (large break LOCA) to determine the sensitivity of PCT to accumulator pressure. This study, in addition to several others, is incorporated into a PCT response surface in order to generate a 95/95 PCT. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Ref. 2).

The accumulators satisfy Criterion 3 of 10 CFR 50.36(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. Three accumulators are required to ensure that 100% of the contents of two 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 two accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

BASES

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. 2) limit of 2200°F.

The Accumulator Applicability is modified by a Note which takes exception to the LCO requirements for the Accumulators to be OPERABLE in MODE 3 with RCS pressure above 1,000 psig for up to 12 hours during the performance of isolation valve testing required by SR 3.4.14.1. The applicability of the Note is restricted solely to the isolation valve testing required by SR 3.4.14.1. In order to perform the required isolation valve testing, the Accumulators must be isolated and various parameters (e.g., pressure, level) must be adjusted. The exception provided by this Note allows operation in MODE 3 with RCS pressure above 1,000 psig for up to 12 hours with Accumulators not configured per the requirements of the LCO such that the Actions for an inoperable Accumulator are not applicable.

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. 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, ability to maintain subcriticality or minimum boron precipitation time may be reduced. An average boron concentration for the injected water is assumed in the Best Estimate LOCA (large break LOCA) analysis. One accumulator up to 100 ppm below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on post-LOCA core subcriticality. The large main steam line break analysis predicts that the accumulators would discharge following the event. However, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

(continued)

ACTIONS (continued)

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 two 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 in WCAP-15049-A, Rev. 1 (Ref. 3).

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. 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2 and SR 3.5.1.3

The borated water volume and nitrogen cover pressure are verified for each accumulator. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator since the static design of the accumulators limits the ways in which the concentration can be changed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Sampling the affected accumulator within 6 hours after a 12% level, indicated, increase (approximately 1% of tank volume) 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), when the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 4).

SR 3.5.1.5

Verification that power is removed from each accumulator isolation valve operator when the pressurizer pressure is ≥ 2000 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 one accumulator would be available for injection given a single failure coincident with a LOCA. Therefore, each isolation valve operator is disconnected by a locked open disconnect device. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

Should closure of a valve occur below 2000 psig, the SI signal provided to the valves would open a closed valve in the event of a LOCA.

REFERENCES

1. FSAR, Chapter 15.
2. 10 CFR 50.46
3. WCAP-15049-A, Rev. 1, April 1999.
4. NUREG-1366, February 1990.

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 feedwater line rupture; 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 simultaneous cold- 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. Approximately 7.5 hours after the initiation of the LOCA, simultaneous cold- and hot-leg recirculation will be initiated to assure termination of boiling. The simultaneous cold- and hot-leg recirculation may consist of high-head pump flow to the cold legs and low-head pump flow to the hot legs or high-head pump flow to the hot legs and low-head pump flow to the cold legs. A manual Train A/Train B power transfer switch is provided to ensure the simultaneous hot-leg and cold-leg recirculation phase of LOCA recovery can be achieved in the unlikely event that Train B power is lost.

(continued)

BACKGROUND (continued)

The ECCS consists of two separate subsystems: centrifugal charging (high head) and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The centrifugal charging system consists of three 100% capacity centrifugal pumps. The “B” centrifugal charging pump functions as a “swing” pump and may be used in either charging system train. 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 the subsystems are the centrifugal charging pumps, the RHR pumps and heat exchangers. Each of the two 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 and then divides again into three supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the RHR pumps divides and feeds an injection line to each of the RCS cold legs. Control 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.

For small LOCAs that do not rapidly depressurize the RCS below the shutoff head of the RHR pumps, the centrifugal charging pumps supply water until the RCS pressure decreases below the RHR 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 centrifugal charging pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, simultaneous cold- and hot-leg recirculation is established.

(continued)

BACKGROUND (continued)

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.

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 immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the 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.

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;

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APPLICABLE SAFETY ANALYSES (continued)

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event; the power reduction limits the amount of heat energy transferred from the RCS into containment via the faulted steam generator. A reduced amount of heat discharged into containment allows for an easier mitigation of the containment temperature transient via the containment safeguards functions (fan coolers and sprays).

Each ECCS subsystem is taken credit for in a large and small break LOCA event at full power (Refs. 3 and 4). The LOCA analysis establishes the minimum flow for the ECCS pumps. These events establish the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The centrifugal charging pumps are also credited in the small break LOCA event. This event, and the LOCA mass and energy release analysis, establish the flow and discharge head at the design point for the centrifugal charging pumps. The SGTR, main feedwater line break, 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 and one centrifugal charging 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. For smaller LOCAs, the centrifugal charging

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APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(c)(2)(ii).

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that 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 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 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 three cold leg injection nozzles. Each centrifugal charging pump must inject ≥ 495.6 gpm and each RHR pump must inject ≥ 3402 gpm at 40 psig RCS pressure. These flows, in conjunction with the RWST minimum boron concentration, provide sufficient cooling water and negative reactivity to ensure that the ECCS acceptance criteria are satisfied. 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. Management of gas voids is important to ECCS OPERABILITY.

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

The LCO is modified by two notes. Note 1 provides an exception to the LCO which allows the centrifugal charging subsystem flowpath or the RHR subsystem flowpath to be isolated. Both the centrifugal charging and the RHR subsystems may be isolated but not at the same time. Each ECCS subsystem flow path 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.

(continued)

BASES

LCO (continued)

Note 2 provides an allowance of up to 4 hours to reposition the state of the power supplies for the RHR discharge to centrifugal charging pump suction valves 8706A and 8706B when transitioning from MODE 4 into MODE 3. This allowance is necessary since the required state of the power supplies for these two valves in MODE 4 is opposite the required state in MODE 3 and time is necessary to restore power to the valves when entering MODE 3 from MODE 4.

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 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. 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 setpoints which are affected by normal mode reduction (steam line pressure-low and pressurizer pressure-low actuation signals) have been 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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

ACTIONS

A.1

With one or more trains inoperable 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.

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. 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.

(continued)

ACTIONS (continued)

B.1 and B.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.

C.1

Condition A is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the facility is in a condition outside of the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

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 locking open the disconnect device to the valve operators ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of REQUIREMENTS the type, described in Reference 6, that can disable the function of both ECCS trains and invalidate the accident analyses. SR 3.5.2.1 is modified by a Note that specifies when this SR is applicable to valves 8132 A/B. Valves 8132 A/B only have the potential to disable both ECCS trains when centrifugal charging pump “A” is inoperable. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

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SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 (continued)

locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing an individual who can rapidly close the system vent flow path if directed.

SR 3.5.2.3

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 OM Code (Ref. 7). This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. For example, if measured on recirculation flow, the centrifugal charging pumps should develop a differential pressure of ≥ 2323 psid and the residual heat removal pumps should develop a differential pressure of ≥ 145 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. Testing is performed in accordance with the INSERVICE TESTING PROGRAM, which encompasses the ASME OM Code. The ASME OM Code provides the activities and Frequencies necessary to satisfy the requirements.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.5.2.4 and SR 3.5.2.5

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 (centrifugal charging and RHR) 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.6

Realignment of valves in the flow path on an SI signal is necessary for proper ECCS performance. These valves have stops (RHR valves) or locking devices (other ECCS valves) to allow proper positioning for limiting total pump flow and/or restrict flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The required verification for the RHR valves, 603 A/B, assures that the associated pump will not be run out. For other ECCS valves, the locking device is verified in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.7

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The inlet screens consist of perforated plates arranged such that their outer edges form a trash rack to reduce clogging of the screen surface by large debris. Each plate is covered by wire mesh to further protect against clogging by smaller debris. Separation between plates is maintained by spacers and each plate is joined to a central perforated cylinder, or inner cage, which collects the flow through each plate. Inspection of the screen plate structure, wire mesh screen, perforated plates and inner cage for evidence of structural distress or abnormal corrosion ensures that the inlet trash racks, screens and inner cages are properly installed and will perform their intended function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.8

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of ECCS locations susceptible to accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.2.8 (continued)

the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the ECCS is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge the system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.

2. 10 CFR 50.46.

(continued)

REFERENCES (continued)

3. FSAR, Section 6, “Engineered Safety Features.”
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. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

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, only one ECCS train consisting of two separate subsystems: centrifugal charging (high head) and residual heat removal (RHR) (low head) is required operable.

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 10 CFR 50.36(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,

(continued)

LCO (continued)

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 three cold leg 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. Management of gas voids is important to ECCS OPERABILITY.

This LCO is modified by two notes. Note 1 allows a 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.

Note 2 provides an allowance of up to 4 hours to reposition the state of the power supplies for the RHR discharge to centrifugal charging pump suction valves 8706A and 8706B when transitioning from MODE 3 into MODE 4. This allowance is necessary since the required state of the power supplies for these two valves in MODE 3 is opposite the required state in MODE 4 and time is necessary to remove power from the valves when entering MODE 4 from MODE 3.

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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4b to an inoperable ECCS centrifugal charging subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS centrifugal charging subsystem and the provisions of LCO 3.0.4b, 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 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 the required ECCS centrifugal charging subsystem inoperable, 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 acceptable when the unit is in MODES 1, 2, and 3 (Ref. 5). Since MODE 4 represents less severe conditions for the initiation of a LOCA, the 72 hour Completion Time is also acceptable for MODE 4. 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 intent of this Condition is

(continued)

ACTIONS

B.1 (continued)

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 the required subsystem may be inoperable, but the ECCS remains capable of delivering 100% of the required flow equivalent.

C.1

With no ECCS centrifugal charging 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 centrifugal charging 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.

D.1

When the Required Actions of Condition B or C cannot be completed within the required Completion Time, a controlled shutdown should be initiated provided that adequate RHR cooling capacity exists to support reaching and maintaining MODE 5 conditions safely. With both RHR subsystems 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 at least one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status. Only then would it be safe to go to MODE 5. 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.2

Verification of proper valve alignment ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render the required ECCS trains inoperable. Securing these valves in position by removal of power by locking open the breaker or disconnect device for the valve operator ensures that they cannot change position as a result of an active failure or be inadvertantly misaligned. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 separate, redundant supply headers 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 manually transferred to the containment sump following receipt of the RWST — Low alarm. 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 begin to close once 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 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

(continued)

BASES

BACKGROUND (continued)

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.

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 and Cooling 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 the results are very insensitive to small changes in boron concentrations. The minimum temperature is an assumption in both the MSLB and inadvertent ECCS actuation analyses.

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 42 seconds without offsite power. This response time includes 2 seconds for electronics delay, a 10 second stroke time for the RWST valves, and a 15 second stroke time for the VCT valves.

For a large break LOCA analysis, the minimum water volume limit of 321,000 gallons and the lower boron concentration limit of 2300 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.

A water volume of 506,600 gallons and the upper limit on boron concentration of 2500 ppm are 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 35°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. An upper temperature assumption of 120°F is used in the small break LOCA analysis and containment OPERABILITY analysis. Exceeding this temperature would result in a higher peak clad temperature, because there would be less heat transfer from the core to the

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BASES

APPLICABLE SAFETY ANALYSES (continued)	injected water for the small break LOCA and higher containment pressures due to reduced containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper assumption on RWST water temperature are used to maximize the total energy release to containment. The RWST satisfies Criterion 3 of 10 CFR 50.36(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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level.
ACTIONS	The ACTIONS are modified by Notes that allow RWST piping flow paths to be unisolated from non-safety related piping under administrative controls for limited periods of time. The piping may be unisolated from non-safety related piping for ≤ 4 hours under administrative controls to perform SR 3.5.4.3 and for ≤ 30 days per fuel cycle under administrative controls for filtration or silica removal.

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BASES

ACTIONS (continued)

These administrative controls consist of (1) Stroking valve Q1(2)G31V010 open and then closed prior to circulating the RWST water through the Spent Fuel Pool Purification System (2) establishing a designated operator to control the valve and (3) establishing a preplanned communication method between the operator and Shift Supervisor. In this way, the flow path can be rapidly isolated in the event of a Reactor Trip or at the direction of the Shift Supervisor. These Notes are to allow recirculation and sampling of the RWST through the Spent Fuel Pool Purification System for filtering as well as operation of the reverse osmosis system to remove silica. These Notes can only be applied during the next two fuel Cycles for each Unit. These Notes cannot be used after Refueling Outages 1R26 (Spring 2015) and 2R24 (Spring 2016).

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.

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 overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is

(continued)

ACTIONS

C.1 and C.2 (continued)

acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 to be above the minimum limit assumed in the accident analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperature is within the operating limit of the RWST. With ambient air temperature within the limit, the RWST temperature should not exceed the limit.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

The RWST water volume should be verified 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.3

The boron concentration of the RWST should be verified 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.

2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

This LCO is applicable only to those units that utilize the centrifugal charging pumps for safety injection (SI). 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

One ECCS train (i.e. one RHR and one centrifugal charging pump) is assumed to fail during a 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, and the LOCA mass and energy release analysis, establish the flow and discharge head at the design point for the centrifugal charging pumps. The steam generator tube rupture, main feedwater line break, and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. 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.

This LCO ensures that seal injection flow with the seal water injection 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 10 CFR 50.36(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. 2).

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 pressure and flow must be known. The flow line resistance is established by adjusting the reactor coolant pump seal injection needle valves to provide a total seal injection flow in the Acceptable Region of Figure 3.5.5-1 at a given pressure differential between the charging header pressure and the pressurizer pressure. The centrifugal charging pump discharge header pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed centrifugal charging pump discharge header pressure result in a conservative valve position should RCS pressure decrease. The additional modifier of this LCO, the seal water injection flow control valve being full open, is required since the valve is designed to fail open for the accident condition. With the discharge pressure and control valve position as specified by the LCO, a resistance limit is established. It is this resistance limit that is used in the accident analyses.

The limit on seal injection flow (operation in the Acceptable Region of Figure 3.5.5-1) and an open wide condition of the seal water injection 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 perform SR 3.5.5.1 and 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.

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

Verification that the manual seal injection throttle valves are adjusted to give a flow within the limits (operation in the acceptable region of Figure 3.5.5-1) ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. A differential pressure that is above the reference minimum value is established between the charging header (PT-121, charging header pressure) and the pressurizer, and the total seal injection flow is verified to be within the limits determined in accordance with the ECCS safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS

SR 3.5.5.1 (continued)

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 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.6 ECCS Recirculation Fluid pH Control System

BASES

BACKGROUND

The Recirculation Fluid pH Control System is a passive system designed to raise the long term pH of the solution in the containment sump following a Design Basis Accident (DBA). The Recirculation Fluid pH Control System consists of three storage baskets containing trisodium phosphate (TSP) as $Na_3PO_4 \cdot 12H_2O \cdot \frac{1}{4}NaOH$. An equivalent amount of trisodium phosphate compound with a different chemical formula may be used. When equivalent compounds are used, the allowable weights/volumes may be different; however, the equivalent amount of trisodium phosphate compound must raise the pH of the recirculating solution into the range of 7.0 to 10.5. In the event of a loss of coolant accident (LOCA), the TSP contained in the storage baskets will be dissolved in the Reactor Coolant System (RCS) and Refueling Water Storage Tank (RWST) inventories lost through the pipe break. The resulting increase in the recirculation solution pH into the range of 7.0 to 10.5 assures that iodine is retained in solution and that chloride induced stress corrosion on mechanical systems and components is minimized (Ref. 1). The Recirculation Fluid pH Control System performs no function during normal plant operation.

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. Fuel damage following a DBA will cause iodine to be released into the reactor coolant and containment atmosphere. Iodine released to the containment atmosphere is absorbed by the containment spray and washed into the containment sump. Since the ECCS water is borated for reactivity control, the recirculation solution in the containment sump will initially be acidic with a pH of approximately 4.5. In a low pH (acidic) solution, some of the dissolved iodine will be converted to a volatile form and evolve out of solution into the containment atmosphere. In order to reduce the potential for elemental iodine evolution, the ECCS recirculation solution is adjusted (buffered) to achieve a long term alkaline pH of no less than 7.0. An alkaline pH promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. In addition to ensuring iodine is retained in solution, an alkaline recirculation solution will minimize chloride induced stress corrosion cracking of austenitic stainless steel

(continued)

BACKGROUND (continued)

ECCS and containment spray components exposed to the high temperature borated water during the recirculation phase of operation after a DBA.

A long term recirculation solution pH of 7.0 to 10.5 also serves to minimize the hydrogen produced by the corrosion of galvanized surfaces and zinc-based paints.

In addition, the determination of this pH range also considered the environmental qualification of equipment in containment that may be subjected to the containment spray.

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution a total of between 10,000 pounds (185 ft^3) and 12,900 pounds (215 ft^3) of TSP (or appropriate weights/volumes for equivalent compounds) is required. The three TSP storage baskets are designed and located to permit the TSP to be dissolved into the containment recirculation sump solution as the post-LOCA water level rises. The stainless steel mesh screen storage baskets are located in the containment sump area anchored to the filler slab at elevation 105-ft 6-in. The post-LOCA ECCS recirculation and containment spray provide mixing to achieve a uniform solution pH.

TSP, because of its stability when exposed to radiation and elevated temperature and its non-toxic nature, is the preferred buffer material. The dodecahydrate form of TSP is used because of the high humidity in the containment during normal operation. Since the TSP is hydrated, it will not absorb large amounts of water from the humid atmosphere and will be less susceptible to physical and chemical change than the anhydrous form of TSP.

APPLICABLE SAFETY ANALYSES

Following the assumed release of radioactive material from a DBA to the containment atmosphere, the containment is assumed to leak at its design value. The LOCA radiological dose analysis assumes the amount of radioactive material available for release to the outside atmosphere is reduced by the operation of the containment spray system. The analysis also assumes the long term pH control of the recirculation fluid retains the dissolved iodine in solution which prevents the iodine from becoming available for release to the atmosphere (Ref. 2). The radiological consequences of a LOCA may

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

be increased if the long term pH of the recirculation solution is not adjusted to 7.0 or greater. Therefore, long term pH control of the post-LOCA recirculation fluid helps ensure the offsite and control room doses are within the limits of 10 CFR 50.67.

The Recirculation Fluid pH Control System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the Recirculation Fluid pH Control System ensures sufficient TSP is maintained in the three TSP storage baskets to increase the long term recirculation fluid pH to between 7.0 and 10.5 following a LOCA. A pH range of 7.0 to 10.5 is sufficient to prevent significant amounts of iodine released from fuel failure and dissolved in the recirculation fluid, from converting to a volatile form and evolving from solution into the containment atmosphere during the ECCS recirculation phase. In addition, an alkaline pH in this range will minimize chloride induced stress corrosion cracking of austenitic stainless steel components, and minimize the hydrogen produced by the corrosion of galvanized surfaces and zinc-based paints.

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution a total of between 10,000 pounds (185 ft^3) and 12,900 pounds (215 ft^3) of TSP (or appropriate weights/volumes for equivalent compounds) is required. The required amount of TSP is determined considering the volume of water involved, the target pH range, and the density of different vendor types of TSP that are available. Although the amount of TSP required is based on mass, a required volume is verified since it is not feasible to weigh the entire amount of TSP in containment.

APPLICABILITY

In MODES 1, 2, 3, and 4 a DBA could cause the release of radioactive material in containment requiring the operation of the ECCS Recirculation Fluid pH Control System. The ECCS Recirculation Fluid pH Control System assists in reducing the amount of radioactive material available for release to the outside atmosphere after a DBA.

(continued)

BASES

APPLICABILITY (continued)

In MODES 5, and 6, the probability and consequences of an event requiring the ECCS Recirculation Fluid pH Control System are reduced due to the pressure and temperature limitations in these MODES. Thus, the ECCS Recirculation Fluid pH Control System is not required OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With the ECCS Recirculation Fluid pH Control System inoperable, the system must be restored to OPERABLE status within 72 hours.

The ability to adjust the recirculation fluid pH to the required range and the resulting iodine retention and corrosion protection may be reduced in this condition. The 72 hour Completion Time is based on the passive nature of the system design and the low probability of an event occurring during this time that would require the ECCS Recirculation Fluid pH Control System function.

B.1 and B.2

If the ECCS Recirculation Fluid pH Control System cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 54 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components,

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 without challenging plant systems. The extended interval to reach MODE 4 allows additional time for restoration of the system and is reasonable considering that the driving force for a release of radioactive material from the RCS is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.5.6.1

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution a total of between 10,000 pounds (185 ft^3) and 12,900 pounds (215 ft^3) of TSP (or appropriate weights/volumes for equivalent compounds) is required. A visual inspection is performed to verify the structural integrity and content volume of the three TSP storage baskets. The baskets are marked with a minimum and maximum fill level that corresponds to a total TSP volume of between 185 ft^3 and 215 ft^3. The verification that the storage baskets contain the required amount of trisodium phosphate is accomplished by verifying that the TSP level is between the indicated fill marks on the baskets. The intent of the surveillance requirement is to verify containment of the TSP by visual inspection. Therefore, broken, crimped, or oxidized screen mesh is acceptable as long as the contents are contained. Also, lumps/caking is an analyzed condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.2.
2. FSAR, Section 15.
3. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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 Accident (DBA). 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, and a shallow 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 cylinder wall is prestressed with a post tensioning system in the vertical and horizontal directions, and the dome roof is prestressed utilizing a three way post tensioning system.

The concrete reactor building is required for structural integrity of the containment under DBA conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. 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

(continued)

BASES

BACKGROUND (continued)

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

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

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). 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 the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day for the first 24 hours and 0.075% thereafter (Ref. 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 0.15% per day in the safety analysis at P_a = 43.8 psig (Ref. 3).

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

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

(continued)

BASES

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, 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 purge 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 $1.0\ L_a$.

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 3.9.3, "Containment Penetrations."

ACTIONS

A.1

If the requirements of SR 3.6.1.2 are not met, the structural integrity of the containment is in a degraded state. SR 3.6.1.2 ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. If a limit of the Program is not met, Condition A allows 24 hours to restore the structural integrity to within limits. The 24-hour Completion Time allows for the correction of minor problems while providing a limit to the amout of time that the structural integrity of containment may be in a degraded condition during at-power conditions.

(continued)

BASES

ACTIONS (continued)

B.1

In the event containment is inoperable for reasons other than Condition A, 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.

C.1 and C.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 such as tendon testing, 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 first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be $\leq 0.6\ L_a$ for combined Type B and C leakage, and $\leq 0.75\ L_a$ 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 $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

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.

SR 3.6.1.2

For ungrouted, post tensioned tendons, this SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are consistent with the requirements of Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a, except where an alternative, exemption or relief has been authorized by the NRC (Ref. 4).

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. FSAR, Chapter 15.

3. FSAR, Section 6.2.

4. Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a.

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, 10 ft in diameter, with a door at each end. The auxiliary hatch is nominally a right circular cylinder, 6 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and 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. The interior doors have a single gasket to seal the door against the bulkhead. The gasket is installed in the bulkhead and the door has a raised edge on the surface of the door that seats against the gasket when closed. The exterior doors have two gaskets to seal the door against the bulkhead. The gaskets are installed concentrically in the bulkhead with a space between them and the door has double, concentric raised edges on the surface of the door that seat against the gaskets when closed. There is a pressure tap that is accessible from the outside of the exterior end of the airlock that may be used to pressurize the gap between the two seals on the exterior door to test for leakage. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches and mechanical pointers for both doors that provide local indication of door position. With power supplied to the door operators, this indication is provided by position indication lights. With power removed from the door operators, this indication is provided by mechanical pointers located beside each door's manual handwheels. A set of handwheels, indicating lights, and manual pointers is located inside the air locks, and on the outside of the air locks on both the auxiliary building and containment sides.

(continued)

BASES

BACKGROUND (continued)	The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.
APPLICABLE SAFETY ANALYSES	The DBAs that result in a release of radioactive material within containment are a loss of coolant accident, a rod ejection accident, and a fuel handling accident in containment (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.15% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, as L_a, the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a (43.8 psig), following a design basis LOCA. 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 10 CFR 50.36(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.

BASES

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 3.9.3, "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 (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."

(continued)

ACTIONS (continued)

A.1, A.2, and A.3

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 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

(continued)

ACTIONS

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

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).

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

(continued)

ACTIONS

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

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.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Section 6.2.
3. NEL Letter NEL-02-0144, dated June 25, 2002.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on 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 forward flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

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-High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the purge and exhaust valves receive an isolation signal on a containment high radiation condition. 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 as assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

(continued)

BASES

BACKGROUND (continued)

Shutdown Purge System (48-inch purge valves CBV-HV-3198A, 3198D, 3196, 3197)

The Shutdown Purge System operates to supply outside air into the containment for ventilation and cooling or heating and 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 purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 48-inch purge valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Minipurge System (8-inch purge valves CBV-HV-2866C, 2866D, 2867C, 2867D)

The Minipurge System operates to:

b. Maintain radioactivity levels in the containment consistent with occupancy requirements with continuous system operation; and

b. Equalize internal and external pressures with continuous system operation.

Since the valves used in the Minipurge System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4.

References to purge valves in the technical specifications apply to both the Shutdown and Minipurge System unless otherwise stated.

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.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 containment purge valves) are minimized. The safety analyses assume that the 48-inch purge valves are closed at event initiation.

The DBA analysis assumes that, except for containment minipurge valves, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a, prior to significant activity release. The containment minipurge isolation total response time of 6 seconds includes signal delay, and containment isolation valve stroke times.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the containment minipurge valves. Two minipurge valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard minipurge isolation valves on each line are provided with diverse power sources, pneumatically operated spring closed valves that will fail closed on the loss of power or air. This arrangement was designed to preclude common mode failures from disabling both minipurge valves on a purge line.

The 48-inch purge valves may be unable to close in the environment following a LOCA. Therefore, each of the 48-inch purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. In this case, the single failure criterion remains applicable to the 48-inch containment purge valves due to failure in the control circuit associated with each valve. Again, the shutdown 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 10 CFR 50.36 (c)(2)(ii).

BASES

LCO	This specification is governing for the containment purge supply and exhaust isolation penetration leakage and 48-inch isolation valve position. The 8-inch containment minipurge supply and exhaust isolation valves may be open for safety-related reasons. Safety-related reasons for venting containment during operation (MODES 1-4) include controlling containment pressure and reducing airborne radioactivity. 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 purge valves must be maintained sealed closed. The valves covered by this LCO are listed along with their associated stroke times in the FSAR (Ref. 2). The normally closed 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. These passive isolation valves/devices are those listed in Reference 2. Purge 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 purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

BASES

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 48-inch 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 purge valve in a 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.

In the event the isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable except for purge valve penetration 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with forward 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, 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.

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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Required Action A.2 is modified by a Note that 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. 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, 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.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration 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 must meet the requirements of Ref. 5. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system. FSAR Table 6.2-31 identifies the following containment isolation valves as being in a Type III penetration (closed system) and having only one containment isolation valve:
Q1/2 B13V026B (Pressurizer pressure generator).

Required Action C.2 is modified by a Note that 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. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, and D.3

In the event one or more penetration flow paths containing containment purge valves, have penetration leakage such that the sum of the leakage for all Type B and C tests is not within limits, purge valve penetration leakage must be restored such that the overall Type B and C testing limit is not exceeded, 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, or blind flange. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to support the penetration meeting the leakage requirements of SR 3.6.3.5. The specified Completion Time is reasonable, considering that one containment purge 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 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, 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 penetration containing a containment purge valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.5 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve penetration does not increase during the time the penetration is isolated. Since more reliance is placed on a single valve while in

(continued)

BASES

ACTIONS

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

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.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, C, or D 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.

F.1

In the event one or more penetration flow paths containing containment purge valves have penetration leakage which exceeds the individual purge valve penetration leakage limit, purge valve penetration leakage must be reduced to within the limit prior to the next time that the unit transitions from MODE 5 to MODE 4. Provided that the penetration flow path leakage does not cause the total leakage from all Type B and C tests to exceed the limits, no additional action is required (i.e., isolation or unit shutdown). If the leakage is sufficient to cause the total leakage from all Type B and C tests to exceed the limits, Condition D also applies.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 48-inch containment purge valve (CBV-HV-3198A, 3198D, 3196, 3197) is required to be verified sealed closed. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside 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, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. 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 includes RHR-MOV-8701A and RHR-MOV-8702A which may be opened and power removed under administrative controls when the plant is in MODE 4 (for ensuring over-pressure protection system operability). This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

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 position, since these were verified to be in the correct position upon locking, sealing, or securing.

Note 1 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. Note 2 provides an allowance to only verify the blind flange on the fuel transfer canal flange after each draining of the canal.

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve in the IST Program is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the INSERVICE TESTING PROGRAM.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B, is required to ensure OPERABILITY. The containment purge and exhaust penetration leakage limit is based on not exceeding the total combined leakage rate limit for all Type B and C testing specified in 5.5.17, Containment Leakage Rate Testing Program. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal (Phase A or Phase B). This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES

1. FSAR, Section 15.
2. FSAR, Section 6.2.
3. Not used.
4. Not used.
5. Standard Review Plan 6.2.4.

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). An inadvertent actuation of the Containment Spray System is not part of the containment pressure response licensing basis for Farley.

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 worst case SLB generates larger mass and energy release than the worst case LOCA. Thus, the SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of 53.4 psig. The containment analysis (Ref. 1) shows the maximum peak calculated containment pressure, P_a, resulting from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA, 43.8 psig, does not exceed the containment design pressure, 54 psig.

The containment was also designed for an external pressure load equivalent to -3.0 psig to account for the external loading from tornado depressurization.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 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 10 CFR 50.36(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 due to tornado induced atmospheric depressurization.
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 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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

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APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is a SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 127°F. This resulted in a maximum containment air temperature of 367°F. The design air temperature is 378°F.

The temperature limit is used to establish the environmental qualification operating envelope for containment. The basis of the containment design air temperature is to ensure the performance of safety-related equipment inside containment (Ref. 2). Thermal analyses show that the containment air temperature remains below the equipment design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System.

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 SLB. 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 10 CFR 50.36(c)(2)(ii).

BASES

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant containment structure 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.

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at four of the following sensor locations with at least two being containment air cooler intake sensors:

Instrument Number	Sensor Location
TE3187 E, F, G, & H	Containment Air Cooler Intake
TE3188 H & I	Lower Compartment
TE3188 J	Reactor (lower)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.2.
2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Cooling systems are 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 Cooling System and Containment Spray System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Cooling System provide redundant cooling methods to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate 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 from the RWST to the containment sump(s).

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products

(continued)

BACKGROUND

Containment Spray System (continued)

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 heat exchangers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

The Containment Spray System is actuated either automatically by a containment High-3 pressure signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps, 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 an RWST level Low-Low alarm is received. The Low-Low level alarm for the RWST signals the operator to manually align the system to the recirculation mode. 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.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 100% of the design cooling requirement, are provided. Each train consists of two fan units supplied with cooling water from a separate train of service water (SW). However, under post-accident conditions, a single fan unit with at least 600 gpm SW flow provides sufficient cooling capacity to meet post accident heat removal requirements. Air is drawn into the coolers through the fan and discharged to the steam generator compartments, pressurizer compartment, and outside the secondary shield in the lower areas of containment.

During normal operation, up to four fan units are operating. The fans are normally operated at high speed with SW supplied to the cooling coils. The Containment Cooling System is designed to limit the

(continued)

BACKGROUND

Containment Cooling System (continued)

ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, unless an LOSP signal is present, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If an LOSP signal is present, only the two fans selected (one per train) will receive an auto-start signal and will start in slow speed. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. In addition, if temperature at the cooler discharge reaches 135°F, fusible links holding dropout plates will open and the fan discharge will no longer be directed through the common discharge header. This function helps to protect the fans in a post-accident environment by reducing the back pressure on the fans. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit 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 loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 52.0 psig (experienced during a SLB). The analysis shows that the peak containment temperature is 367°F (experienced during a 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, "Containment Air Temperature," for a detailed discussion.)

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The analyses and evaluations assume a unit specific power level of 102%, one containment spray train and one containment cooling fan operating, and initial (pre-accident) containment conditions of 127°F and -1.5 to +3.0 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 -2.9 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 High-3 pressure safety analysis limit to achieving full flow through the containment spray nozzles. The Containment Spray System total response time is a function of the LOCA (or MSLB) break size and depends on the timing of the containment High-1 (safety injection) and High-3 (containment spray) pressure signals with respect to diesel start and LOSP block loading. For large break LOCAs which pressurize containment rapidly, the High-3 signal is processed prior to ESS loading step 2, so the delay time includes diesel generator start, ESS loading, containment spray pump startup, and spray discharge valve stroke. However, MSLBs and smaller LOCAs result in slower containment pressurization and, therefore, may delay High-1 and/or High-3 signal generation. If High-3 is delayed beyond ESS loading step 2, the spray pumps will not be energized until after loading step 6. These delays are reflected in the response time testing criteria (Ref. 4). The delay for spray line fill is conservatively accounted for in the containment analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment cooling train performance for post accident conditions is given in Reference 3. The result of the analysis is that each train having at least one OPERABLE fan unit with at least 600 gpm SW flow can provide 100% of the required peak cooling capacity during the post accident condition. The train post accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 5.

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-1 pressure setpoint to achieving full Containment Cooling System air and safety grade cooling water flow.

The Containment Cooling System total response time of 87 seconds, includes signal delay, DG startup (for loss of offsite power), and service water pump startup times (Ref. 4).

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one containment cooling train with a single OPERABLE fan unit and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). Additionally, one 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 and two containment cooling trains with a single OPERABLE fan unit per cooling train with at least 600 gpm SW flow must be OPERABLE. Therefore, in the event of an accident, at least one train in each system operates, assuming the worst case single active failure occurs.

Each Containment Spray System typically includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and manually transferring suction to the containment sump. Management of gas voids is important to Containment Spray System OPERABILITY.

Each Containment Cooling System typically includes cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

BASES

APPLICABILITY

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

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and the Containment Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.1 and B.2

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 overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 54 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 7). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

As stated in Reference 7, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 4 allows 48 hours to restore the containment spray train to OPERABLE status in MODE 3. This is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one of the required containment cooling trains inoperable, the inoperable required containment cooling train must be restored to OPERABLE status within 7 days. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System and the low probability of DBA occurring during this period.

(continued)

BASES

ACTIONS

D.1

With two required containment cooling trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, the iodine removal function of the Containment Spray System, and the low probability of DBA occurring during this period.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 7). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 7, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

Required Action E.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

F.1

With two containment spray trains or any combination of three or more containment spray and cooling trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1 (continued)

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing an individual who can rapidly close the system vent flow path if directed.

SR 3.6.6.2

Operating each required containment cooling train fan unit for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The fans are started from the control room (unless already operating). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.6.6.3

Verifying that the SW flow rate to each containment cooling train is ≥ 1600 gpm provides assurance that the design flow rate will be achieved (Ref. 3). However, safety analyses show that, under post-accident conditions, a flow rate of 600 gpm to one fan unit is sufficient to meet the post-accident heat removal requirements. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 ensures that spray pump performance has not degraded during the cycle. On recirculation flow each pump develops a discharge pressure of ≥ 210 psig. On full flow testing, each pump is run and the flow directed through the containment spray system test line into the refueling canal. The flow is throttled across the pump curve via the regulating globe valve in the test line. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code for Operation and Maintenance of Nuclear Power Plants (Ref. 6). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow and full flow to the refueling canal. Taken together, these tests

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.4 (continued)

confirm the pump design curve and are 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.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control 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 and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High-3 pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The surveillance of containment sump isolation valves is also required by SR 3.5.2.5. A single surveillance may be used to satisfy both requirements.

SR 3.6.6.7

This SR requires verification that each containment cooling train actuates upon receipt of an actual or simulated safety injection signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.9

Containment Spray System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the containment spray trains and may also prevent water hammer and pump cavitation.

Selection of Containment Spray System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas our could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The Containment Spray System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the Containment Spray System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

Containment Spray System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.9 (continued)

required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

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.
4. FSAR, Section 7.3.
5. FSAR, Section 15.
6. ASME Code for Operation and Maintenance of Nuclear Power Plants.
7. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

DELETED
Additional pages deleted:
B 3.6.7-2
B 3.6.7-3
B 3.6.7-4
B 3.6.7-5
B 3.6.7-6

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Mixing System (HMS)

BASES

The HMS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The post accident HMS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of two fans with their own motors and controls. Each train is sized for 15,000 cfm. The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since a single fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure.

Air is drawn from the steam generator compartments by the locally mounted mixing fans and is discharged toward the upper regions of the containment. This complements the air patterns established by the containment air coolers, which take suction above the operating floor level and discharge to the lower regions of the containment, and the containment spray, which cools the air and causes it to drop to lower elevations. The systems work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

When performing their post accident hydrogen mixing function, the hydrogen mixing fans are designed to prevent motor overload in a post accident high pressure environment. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. Each train is redundant (in excess of full required capacity) and is powered from an independent ESF bus.

APPLICABLE SAFETY ANALYSES

The HMS provides the capability for reducing the local hydrogen concentration to approximately the bulk average concentration. The limiting DBA relative to hydrogen concentration is a LOCA.

Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

If the maximum calculated flow rate is used, the total ventilation system requirements needed to handle any break location are 5058, 2319, and 1932 SCFM if based upon allowable compartmental hydrogen limits of 3.0, 3.5, and 4.0 percent, respectively. These valves are based on taking the case where the sum of the required flow rates for each compartment, on a consistent basis, is maximized (Ref.4). With each fan capable of delivering 7500 SCFM, a single fan is capable of fulfilling the flow requirements.

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

LCO

Two HMS trains must be OPERABLE, with power to each from an independent, safety-related power supply. Each train consists of two fans with their own motors and controls and is automatically initiated

(continued)

LCO (continued)

by a Safety Injection signal. Only one fan per train is required OPERABLE for the train to be considered OPERABLE.

Operation with at least one HMS fan provides the mixing necessary to ensure uniform hydrogen concentration throughout containment.

APPLICABILITY

In MODES 1 and 2, the two HMS trains ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 volume percent in containment assuming a worst case single active failure.

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the HMS is low. Therefore, the HMS is not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the HMS is not required in these MODES.

ACTIONS

A.1

With one HMS train inoperable, the inoperable train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE HMS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability, although the capacity of a single fan is sufficient to provide adequate mixing. The 30 day Completion Time is based on the availability of the other HMS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the Containment Spray System and Post Accident Hydrogen Purge System.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With two HMS trains inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capability is provided by the containment Post Accident Hydrogen Purge System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. Both the initial verification and all subsequent verifications may be performed as an administrative check, by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two HMS trains inoperable for up to 7 days. Seven days is a reasonable time to allow two HMS trains to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

C.1

If an inoperable HMS 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. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Operating each HMS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls (including starting from the control room) are functioning properly. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.2

Verifying that each HMS fan speed is ≥ 1320 rpm ensures that each train is capable of maintaining localized hydrogen concentrations below the flammability limit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.3

This SR ensures that each HMS train responds properly to a Safety Injection actuation signal. The Surveillance verifies that each fan starts from the nonoperating condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Deleted

2. Deleted

3. Regulatory Guide 1.7, Revision 1.

4. WCAP 7901, Revision 1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Reactor Cavity Hydrogen Dilution System (RCHDS)

BASES

BACKGROUND

The RCHDS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The post accident RCHDS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of one fan with its own motor and controls. Each train is sized for 270 cfm (Unit 1) and 1570 cfm (Unit 2).

The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since each train fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure. The RCHDS ventilates the reactor cavity to ensure that this volume is available for the dilution of containment hydrogen, and to maintain hydrogen concentrations in this volume in equilibrium with that of the remainder of the containment. The RCHDS fans discharge into the reactor cavity through a circular header embedded in the cavity wall at an elevation approximately coincident with that of the lower reactor vessel head. The RCHDS discharge flows from the cavity upward around the reactor vessel and outward through the incore instrument chase. The RCHDS fans take suction from the periphery of the containment just below the operating floor. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. The RCHDS and Hydrogen Mixing System work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The RCHDS provides the capability for reducing the local hydrogen concentration to approximately the bulk average concentration. The limiting DBA relative to hydrogen concentration is a LOCA.

Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Ref. 3 are used to maximize the amount of hydrogen calculated.

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

LCO

Two RCHDS trains must be OPERABLE, with power to each from an independent, safety related power supply. Each train consists of one fan with its own motor and controls which is automatically actuated by a Safety Injection signal. Operation with at least one RCHDS train provides the mixing necessary to ensure uniform hydrogen concentration throughout the reactor cavity and containment.

APPLICABILITY

In MODES 1 and 2, the two RCHDS trains ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 volume percent in containment assuming a worst case single active failure.

(continued)

BASES

APPLICABILITY (continued)

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the RCHDS is low. Therefore, the RCHDS is not required in MODE 3 or 4.

In MODE 5 or 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RCHDS is not required in these MODES.

ACTIONS

A.1

With one RCHDS train inoperable, the inoperable train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RCHDS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the other RCHDS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the Containment Spray System and the Post Accident Venting System.

B.1

If an inoperable RCHDS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a

(continued)

BASES

ACTIONS

B.1 (continued)

MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Operating each RCHDS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls are functioning properly and that each fan may be started by operator action from the control room. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.6.9.2

This SR ensures that each RCHDS train responds properly to a Safety Injection signal. The Surveillance verifies that each fan starts from the non-operating condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Deleted

2. Deleted

3. Regulatory Guide 1.7, Revision 0.

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 steam header, outside containment, upstream of the main steam isolation valves, as described in the FSAR, Section 10.3.7 (Ref. 1). The MSSVs must have sufficient capacity to limit the 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. In addition, each MSSV has a 16 sq. in. orifice to limit steam flow.

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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

One turbine trip analysis is performed assuming primary system pressure control via operation of the 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 ΔT 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 Section 15.2.2 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 analyses or conservatively arrived at by 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 SG 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

MSSVs on the same steam generator it is necessary to prevent this power increase by 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 maximum allowable power levels specified in Table 3.7.1-1 are overly conservative at middle and end-of-life conditions, when the MTC is not positive. Therefore, a specific analysis which credits a middle-of-life MTC was performed to relax the power reduction associated with one inoperable MSSV per steam generator. In addition, for the above case, no reduction in the Power Range Neutron Flux-High trip setpoint is required. The middle-of-life analysis assumes a -10 pcm/degree F MTC and demonstrates that the maximum allowable power level associated with one inoperable MSSV per steam generator can be relaxed to 87% RTP when cycle burnup is ≥ 14,000 MWD/MTU. The MTC value at 14,000 MWD/MTU is verified to be more negative than -10 pcm/degree F for each reload cycle.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(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.

(continued)

BASES

LCO (continued)

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.

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 Reference 2 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

(continued)

BASES

ACTIONS

A.1 (continued)

turbine and the 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 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 described in the attachment to Reference 6, with an appropriate allowance for 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 the 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 the flow capacity of the remaining OPERABLE MSSVs is insufficient. Therefore, in addition to reducing THERMAL POWER within 4 hours as required by Required Action B.1, the Power Range Neutron Flux-High trip setpoint must be reduced to less than or equal to the applicable value corresponding to the number of OPERABLE MSSVs specified in Table 3.7.1-1 within 36 hours as required by Required Action B.2 (applicable in MODE 1 only). The safety analysis of the loss of load/turbine trip event analyzed from part power conditions to specifically support the requirements of Table 3.7.1-1, explicitly credits the Power Range Neutron Flux-High trip function to ensure that the peak power does not exceed an acceptable level. With two or more MSSVs inoperable on one or more steam generators, the reduced Power Range Neutron Flux-High trip setpoints will also limit the peak power to an acceptable level for an RCCA withdrawal at power transient occurring from similar conditions.

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 6, with an appropriate allowance 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 plant INSERVICE TESTING PROGRAM incorporates the requirements of the applicable edition of the ASME OM Code (Ref. 4)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

as modified with any approved relief requests.

The OM Code 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 in the accompanying LCO, 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 10.3.7.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components, 1971 edition.
3. FSAR, Section 15.2.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
5. (Not used)
6. NRC Information Notice 94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.

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.

Two MSIVs are located in each main steam line outside containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV 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 high steam line flow coincident with low-low T_{avg}, low steam line pressure or high-high containment pressure.

Each MSIV is provided with a normally open, three-way solenoid valve which, when deenergized, provides instrument air to the actuator cylinder. As the solenoid valves are normally deenergized, loss of dc power will not cause the MSIV to close. An air reservoir is also provided for each MSIV, to allow it to remain open upon loss of instrument air. Each solenoid valve receives a separate signal from the ESF actuation system and has a separate 125 V dc power supply. When the solenoid valve is energized, it vents the air reservoir and actuator cylinder to the atmosphere and closes the MSIV.

Each set of MSIVs has two series of MSIV bypass valves. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

discussed in the FSAR, Section 6.2 (Ref. 2). It is also affected by the accident analysis of the secondary system pipe rupture events presented in the FSAR, Section 15.4.2 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand). Since two MSIVs are available, the failure of a single MSIV is not significant.

A large SLB inside containment at 102% power is the limiting case for the release of steam mass and energy resulting in a peak containment temperature; a large SLB inside containment at 30% power is the limiting case for the release of steam mass and energy resulting in a peak containment pressure.

For SLB events at full power, the SG temperature is at its maximum, which maximizes the available energy release to containment. At lower powers, the steam generator inventory is at its maximum, which maximizes the available release to the containment. Since the MSIVs stop flow only in the forward direction, the total energy release to containment includes the entire steam piping volume downstream of the isolation valves for the steam generators, including the steam line header and steam piping. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. A large SLB at hot zero power is the limiting cooldown case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of one ECCS train.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. For this accident scenario, steam is discharged into containment from all steam generators until the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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. A large SLB inside containment at 102% power is the limiting case for the release of steam mass and energy resulting in a peak containment temperature; a large SLB inside containment at 30% power is the limiting case for the release of steam mass and energy resulting in a peak containment pressure. The analysis includes the scenario with offsite power available in which the reactor coolant pumps continue to circulate coolant through the SGs, maximizing the primary to secondary heat transfer. Significant single failures considered include failure of an ESF train (one Containment Spray System train and one Containment Air Cooler) and main feedwater flow control.

b. A break outside of containment and upstream from 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.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of one MSIV and bypass valve isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break.

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

LCO

This LCO requires that all 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.

(continued)

BASES

LCO (continued)

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents such that offsite exposures are less than the 10 CFR 50.67 (Ref. 4) limits.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when one MSIV in each steam line is closed, 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, and the steam generator energy is low.

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 Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each steam line. The Completion Time(s) of the inoperable MSIV Systems will be tracked separately for each steam line starting from the time the Condition was entered for that steam line.

A.1

With one MSIV inoperable in one or more steam lines in MODE 1, action must be taken to restore the inoperable MSIV to OPERABLE status within 72 hours. Some repairs to the MSIV can be made with the unit at power. The 72 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time that would require the MSIVs to close and the remaining OPERABLE MSIV in the steam line. This Completion Time is also consistent with the Completion Times provided for a single inoperable train in other ESF systems that contain redundant trains of equipment.

(continued)

BASES

ACTIONS (continued)

B.1

With two MSIVs inoperable in one or more steam lines in MODE 1, action must be taken to restore one MSIV to OPERABLE status in the affected steam line(s) within 4 hours. In this Condition, the affected steam line has no OPERABLE automatic isolation capability. The 4-hour Completion Time allows for minor repairs or trouble shooting that may prevent a unit shutdown to MODE 2 and is reasonable considering the low probability of an accident occurring during this time that would require the MSIVs to close and the reduced potential for a plant transient (shutdown to MODE 2) provided by the 4 hours allowed for restoration.

C.1

If the MSIV cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a Mode in which the ACTIONS provide the option to close the inoperable MSIV and accomplish the required safety function by isolating the affected steam line. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition D or E entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 in an orderly manner without challenging unit systems.

D.1

Required Action D.1 is applicable when one or more steam lines have a single inoperable MSIV in MODE 2 or 3. Since the MSIVs are required OPERABLE in MODES 2 and 3, the inoperable MSIV(s) may either be restored to OPERABLE status or the affected steam line isolated by closing at least one MSIV in that steam line. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 7 day Completion Time is reasonable considering the plant condition, the low probability of an event occurring that would require the MSIV to close, and the remaining OPERABLE redundant MSIV in the affected steam line(s).

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, and the affected steam line is isolated by a closed MSIV, the MSIV must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions

(continued)

BASES

ACTIONS

D.1 (continued)

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.

E.1

With two MSIVs inoperable in one or more steam lines in MODE 2 or 3, action must be taken to restore one MSIV to OPERABLE status or verify one MSIV closed in the affected steam line(s) within 4 hours. In this condition, the affected steam line has no OPERABLE automatic isolation capability. Verifying one MSIV system closed ensures the safety function is accomplished for that steam line. The 4-hour Completion Time is reasonable considering the low probability of an accident occurring during this time that would require a MSIV to close.

For inoperable MSIVs that cannot be restored to OPERABLE status and are closed, the MSIV must be verified closed on a periodic basis. Verification that the MSIV is closed on a periodic basis is necessary to ensure that the safety analysis assumptions remain valid. The 7-day Completion Time is reasonable, based on engineering judgment, considering the MSIV indications available in the control room, and other administrative controls, to ensure that these valves are closed.

F.1 and F.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.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 7 seconds on an actual or simulated actuation signal. The MSIV closure time is assumed in the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1 (continued)

accident and containment analyses. This Surveillance is normally performed while returning the unit to operation following a refueling outage.

The Frequency is in accordance with the INSERVICE TESTING PROGRAM, which encompasses the ASME OM Code (Ref. 5). Operating experience has shown that these components usually pass the Surveillance when performed in accordance with the INSERVICE TESTING PROGRAM. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. If desired, this allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated. This surveillance may be performed in lower modes but must be performed prior to entry into MODE 2.

REFERENCES

1. FSAR, Section 10.3.
2. FSAR, Section 6.2.
3. FSAR, Section 15.4.2.
4. 10 CFR 50.67.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Stop Valves and Main Feedwater Regulation Valves (MFRVs) and Associated Bypass Valves

BASES

BACKGROUND

The MFRVs provide the primary main feedwater (MFW) flow isolation to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the Main FW Stop Valves is to provide a diverse backup isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFRVs and associated bypass valves or Main FW Stop Valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFRVs or Main FW Stop Valves. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the valves will be mitigated by their closure. Closure of the MFRVs and associated bypass valves, or Main FW Stop Valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The Main FW Stop Valves isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFRV and associated bypass valve, and one Main FW Stop Valve, are located on each MFW line, outside containment. The Main FW Stop Valves and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following Main FW Stop Valve or MFRV closure. The piping volume from these valves to the steam generators is accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

The MFRVs and associated bypass valves close on receipt of a T_{avg} — Low coincident with reactor trip (P-4), Safety Injection, or steam generator water level — high high signal. The Main FW Stop Valves close on a SGFP trip signal which is initaited by high-high SG water level or SI. These valves may also be actuated manually. The

(continued)

BASES

BACKGROUND (continued)

MFRVs and associated bypass valves, or the Main FW Stop Valves isolate the feedwater line penetrating containment, and ensure that the consequences of events do not exceed the capacity of the containment heat removal systems.

The MFRVs and the Main FW Stop Valves are part of the Condensate and Feedwater System as described in the FSAR, Section 10.4.7 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MFRVs and Main FW Stop Valves is primarily established by the analyses for the large SLB. Although the Main FW Stop Valves are not specifically credited in the accident analyses, these islation valves provide a diverse backup isolation function to the MFRVs. Closure of the MFRVs and associated bypass valves, or Main Feedwater Stop 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 a Main FW Stop Valve and MFRV, or Main FW Stop Valve and MFRV bypass valve to close following an SLB or an excess feedwater event can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

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

LCO

This LCO ensures that the MFRVs and their associated bypass valves or Main FW Stop Valves will isolate MFW flow to the steam generators, following an excess feedwater event or main steam line break. These valves will also isolate the nonsafety related portions from the safety related portions of the system.

This LCO requires that three MFRVs and associated bypass valves and three Main FW Stop Valves be OPERABLE. The MFRVs and the associated bypass valves and the Main FW Stop Valves are considered OPERABLE when isolation times are within limits and they close on the appropriate signal(s).

(continued)

BASES

LCO (continued)

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB inside containment. If a feedwater isolation signal on high 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 Main FW Stop Valves and MFRVs and their associated bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1 and 2, the Main FW Stop Valves and MFRVs and their 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 3, 4, 5, and 6, AFW and RHR are used for heat removal. Therefore, the Main FW Stop Valves and the MFRVs and their associated bypass valves are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

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

With one Main FW Stop 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable Main FW Stop 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.

B.1 and B.2

With one MFRV 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 MFRVs, 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 the valves are closed or isolated.

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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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.

D.1

With the combination of inoperable Main FW Stop Valves, MFRVs and associated bypass valves such that a feedwater line has no OPERABLE means of isolation, action must be taken to restore one of the isolation valves to OPERABLE status or isolate the affected feedwater line within 8 hours. The feedwater lines may be isolated by either a single Main FW Stop Valve or the combination of a MFRV and its associated bypass valve. With one means of isolation restored to OPERABLE status, operation may continue with any of the remaining inoperable valves being addressed by the appropriate Condition(s) (A, B and/or C) of this LCO. With the affected feedwater line isolated, the isolation safety function is accomplished and power operation is limited accordingly. The Completion Time is reasonable considering the low probability of an event occurring that would require feedwater isolation during this time, and in most cases, the only action necessary for feedwater line isolation would be to close and deactivate the necessary valve(s).

E.1 and E.2

If the Main FW Stop Valves and MFRV(s) and their associated bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated 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. The allowed Completion Time is reasonable, based on operating

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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 Main FW Stop Valve and MFRV and its associated bypass valve is in accordance with the requirements of the INSERVICE TESTING PROGRAM. The Main FW Stop Valve and MFRV closure times are assumed in the accident and containment analyses. This Surveillance is normally performed during return of the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME OM Code (Ref. 2).

The Frequency for this SR is in accordance with the INSERVICE TESTING PROGRAM. Operating experience has shown that these components usually pass the Surveillance when performed in accordance with the INSERVICE TESTING PROGRAM.

REFERENCES

1. FSAR, Section 10.4.7.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

B 3.7 PLANT SYSTEMS

B 3.7.4 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 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 three steam generators is provided. Each ARV line consists of one ARV and two associated manual isolation valves.

The ARVs are provided with upstream manual isolation valves 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 an alternate air supply consisting of two redundant air compressors which, on a loss of pressure in the normal instrument air supply, may be aligned to supply air to the ARVs for remote or local control of the valves.

A description of the ARVs is found in Reference 1. The ARVs are OPERABLE when they can be operated remotely, either automatically or manually; or locally, either pneumatically or manually. Handwheels are provided for local manual operation.

APPLICABLE SAFETY ANALYSES

The design basis (size) of the ARVs is established by the capability to cool the unit to RHR entry conditions. The valve size is determined by the design cooldown rate in the last hour of plant cooldown when the SG shell side pressure is reduced.

The ARVs provide the capability for the removal of reactor decay heat during periods when the main condenser is not available to cool down

(continued)

APPLICABLE SAFETY ANALYSES (continued)

the unit to RHR entry conditions. The limiting design basis accident for the ARVs is established by the Steam Generator Tube Rupture (SGTR) event (Ref. 2). The SGTR event is analyzed for two cases to determine that the offsite doses meet the NRC acceptance criteria. That is, for the case of an accident initiated Iodine spike, the doses from the accident are a small fraction of the limits defined in 10 CFR 50.67 and for the case of a pre-accident Iodine spike, the doses from the accident are within the limits defined in 10 CFR 50.67. The SGTR event assumes recovery with and without offsite power. The loss of offsite power assumption results in the ARVs being relied upon to reduce RCS temperature to recover from an SGTR and also to reduce RCS temperature and pressure to RHR entry conditions. The accident analysis does not assume a specific method of valve operation to mitigate the accident. The analysis assumes the SG tube break flow is terminated within 30 minutes of the initiation of the accident.

The recovery from the SGTR event requires a rapid cooldown to establish adequate subcooling as a necessary step to allow depressurization of the RCS to terminate the primary to secondary break flow in the ruptured steam generator. The time required to terminate the primary to secondary break flow in the SGTR event is more critical than the time required to cool the RCS down to RHR entry conditions for this event and other accident analyses. Thus, the SGTR is the limiting event for the ARVs.

Each ARV is equipped with two manual isolation valves in the event an ARV spuriously fails to open or fails to close during use.

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

LCO

Three ARV lines are required to be OPERABLE. One ARV line is required from each of three steam generators to ensure that at least one ARV line is available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second ARV line on an unaffected steam generator. At least one manual isolation valve must be OPERABLE to isolate a failed open ARV line. A closed manual isolation valve does not render it or its ARV line inoperable. The accident analysis does not model a specific method of valve operation and allows 30 minutes to terminate the SG tube break flow. Sufficient time is available to unisolate and manually operate the ARV.

(continued)

BASES

LCO (continued)

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 (even if isolated) when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand, either remotely or locally via manual control.

APPLICABILITY

In MODES 1, 2, and 3, the ARVs are required to be OPERABLE.

In MODE 4, the pressure and temperature limitations are such that the probability of an SGTR event requiring ARV operation is low. In addition, the RHR system is available to provide the decay heat removal function in MODE 4. Therefore, the ARVs are not required to be OPERABLE in MODE 4 to satisfy the safety analysis assumptions of the DBA. However, the capability to remove decay heat from a SG required to be OPERABLE in MODE 4 by LCO 3.4.6, "RCS Loops – MODE 4" is implicit in the requirement for an OPERABLE SG and may require the associated ARV be capable of removing that heat if the normal decay heat removal system (steam dump) is not available.

In MODE 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 or more ARV lines inoperable, action must be taken to restore all but one ARV line to OPERABLE status. Since the manual isolation valves can be closed to isolate an ARV, some repairs may

(continued)

BASES

ACTIONS

B.1 (continued)

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.

C.1 and C.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 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ARVs must be able to be opened either remotely or locally 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.2

The function of the manual isolation valve is to isolate a failed open ARV. Cycling the manual isolation valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the manual isolation valve during unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. FSAR, Section 10.3.
2. FSAR, Section 15.4.3.

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 turbine-driven and motor-driven AFW pumps take suction through separate and independent suction lines (one for the turbine-driven pump and one shared by both motor-driven pumps) from the condensate storage tank (CST) (LCO 3.7.6, “Condensate Storage Tank (CST)”) and pump to the steam generator secondary side via separate and independent lines up to the common connection to the main feedwater (MFW) piping to each steam generator 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, “Main Steam Safety Valves (MSSVs)”) or atmospheric relief valves (ARVs) (LCO 3.7.4, “Atmospheric Relief Valves (ARVs)”). 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. The pumps are equipped with recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent Class 1E power supply and feeds all steam generators through a common header. 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 turbine driven AFW pump supplies a common header capable of feeding all steam generators via DC solenoid air operated control valves actuated by the Engineered Safety Feature Actuation System (ESFAS). Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

One pump at full flow is sufficient to remove decay heat and cool the unit (normal cooldown) to residual heat removal (RHR) entry conditions.

(continued)

BASES

BACKGROUND (continued)

The design of the AFW system ensures that the RCS can be cooled down to less than 350°F (RHR entry conditions) from normal operating conditions in the event of any of the following incidents:

- Loss of Normal Feedwater,
- Loss of Offsite Power,
- Feed Line Break,
- Main Steam Line Break,
- Accidental Depressurization of the SGs,
- SG Tube Rupture,
- High Energy Line Break,
- Small Break LOCA,
- Cooldown following a Reactor Trip,
- Station Blackout.

Each motor-driven AFW pump delivers a total of at least 285 gpm to all SGs which are at a pressure of 1138 psia. The minimum flow requirement for a motor-driven AFW pump is based on a high energy line break in the steam supply line to the turbine-driven AFW pump. In this scenario, only one motor-driven AFW pump will be the source of AFW. The turbine-driven AFW pump delivers a total of at 350 gpm to all SGs which are at a pressure of 1138 psia. The minimum requirement for the turbine-driven AFW pump is based on a station blackout event. In this scenario, the turbine-driven AFW pump will be the only source of AFW. Additionally, any single AFW pump (turbine or motor-driven) is capable of providing sufficient flow (350 gpm) to all SGs at a pressure of 1020 psia to cooldown the RCS to RHR entry conditions during a normal cooldown of the unit (not a reactor trip). For all other incidents listed above, except for the high energy line break in the steam supply to the turbine-driven AFW pump, the station blackout event, and the normal unit cooldown discussed previously, two out of three AFW pumps (motor or turbine-driven combination) are required to satisfy the flow demand.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ARVs.

The motor-driven AFW pumps actuate automatically on the following signals:

a. Trip of both SG main feedwater pumps;

(continued)

BASES

BACKGROUND (continued)

b. Low-low water level signals from two out of three level transmitters on any one SG;
c. Safety Injection signal; and
d. Loss of offsite power.

The steam supply to the turbine-driven AFW pump is automatically actuated on the following signals:

a. Loss of power signal (two out of three reactor coolant pump bus undervoltage); and
b. Low-low water level signals from two out of three level transmitters on any two out of three SGs.

The AFW System is discussed in the FSAR, Section 6.5 (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% and setpoint tolerance plus any 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 line breaks. However, the operability of the AFW System in MODE 4 is not assumed in the safety analysis.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB);

b. Main Steam Line Break (MSLB); and

c. Loss of MFW.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Two of the three AFW pumps are required to ensure the flow demand for the most limiting DBAs and transients is satisfied. In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure. In such a case, the ESFAS logic may not detect the affected steam generator if the backflow check valve to the affected MFW header worked properly. The AFW flow delivered to the broken MFW header is limited by the flow restrictor installed in the AFW line until flow is terminated by the operator. Sufficient flow would be delivered to the intact SGs after isolation.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC solenoid air operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(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 (steam and electrical power) are required to be OPERABLE to ensure the availability of RHR 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 trains are configured into two flowpaths, one for the motor-driven pumps and one for the turbine-driven pump. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam

(continued)

BASES

LCO (continued)

generators are OPERABLE. This requires that the two motor-driven AFW pump trains be OPERABLE with one shared flow path, each supplying AFW to all steam generators. In addition, the turbine driven AFW pump train 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 via its associated flow path. The control room manual actuation switches for each AFW pump shall also be OPERABLE. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. A flow path is operable when it is capable of supporting the required AFW flow.

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 MFW 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. However, the OPERABILITY of the AFW system in MODE 4 is not assumed in the safety analysis and this LCO does not require the AFW system OPERABLE in MODE 4.

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 3.0.4b 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 3.0.4b, 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.

<u>A.1</u>

If the turbine driven AFW train is inoperable due to one inoperable steam supply, or if turbine driven pump is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

(continued)

BASES

ACTIONS

A.1 (continued)

a. For the inoperability of the turbine driven AFW pump due to one inoperable steam supply, the 7 day Completion time is reasonable since there is a redundant steam supply line for the turbine driven pump and the turbine driven train is still capable of performing its specified function for most postulated events.

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion time is reasonable due to the minimal decay heat levels in this situation.

c. For both the inoperability of the turbine driven pump due to one inoperable steam supply and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling, the 7 day Completion time is reasonable due to the availability of redundant OPERABLE motor driven AFW pumps; and due to the low probability of an event requiring the use of the turbine driven AFW pump.

Condition A is modified by a Note which limits the applicability of the Condition for an inoperable turbine driven AFW pump in MODE 3 to when the unit has not entered MODE 2 following a refueling. Condition A allows one AFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

B.1

With one of the required AFW trains (pump or flow path) inoperable for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. A flow path is inoperable if it is blocked such that the required AFW flow cannot be delivered. 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 the redundant capabilities afforded by the AFW System, the time needed for repairs, and the low probability of a DBA occurring during this time period.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one of the required motor driven AFW trains (pump or flow path) inoperable and the turbine driven AFW train inoperable due to one inoperable steam supply, action must be taken to restore the affected equipment to OPERABLE status within 24 hours. Assuming no single active failures when in this condition, the accident (a FLB or MSLB) could result in the loss of the remaining steam supply to the turbine driven AFW pump due to the faulted SG. In this condition, the AFW system may no longer be able to meet the required flow to the SGs assumed in the safety analysis due to the analysis requiring flow from two AFW pumps.

The 24 hour Completion Time is reasonable based on the remaining OPERABLE steam supply to the turbine driven AFW pump, the availability of the remaining OPERABLE motor driven AFW pump, and the low probability of an event occurring that would require the inoperable steam supply to be available for the turbine driven AFW pump.

D.1 and D.2

When Required Action A.1, B.1, C.1, or C.2 cannot be completed within the required Completion Time, or if two AFW trains are inoperable for reasons other than Condition C, 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.

In MODE 4, AFW is not required since the RHR system is available.

(continued)

BASES

ACTIONS (continued)

E.1

If all three AFW trains are inoperable, 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 E.1 is modified by a Note indicating that all required MODE changes 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.

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 SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, 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. 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 (i.e., the intended safety function) continues to be maintained.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 (continued)

In addition, this surveillance includes verification that the stop check valves 3350A, 3350B, and 3350C are in the open position with the breaker to the valve operators locked open.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 OM Code (Ref 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME OM Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

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 steam generators 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 (automatic pump start) signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.3 (continued)

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, 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. 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 (i.e., the intended safety function) continues to be maintained.

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 signal in MODES 1, 2, and 3. The motor-driven pumps must be verified to start on SI, SG water level low-low in any SG, and loss of offsite power. The turbine-driven pump must be verified to start on under-voltage on two out of three RCP buses and SG water level low-low in two SGs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a two Notes. The first Note indicates the SR may be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

The second Note states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.4 (continued)

incapable of automatic initiation without declaring the train(s) inoperable. 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 (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.5

This SR verifies that the air stored in turbine-driven AFW pump steam admission valve air accumulators is sufficient to open valves Q1(2)N12V001A-A and Q1(2)N12V001B-B. Each steam admission valve has an air accumulator associated with it. The air accumulators provide sufficient air to ensure the operation of the steam admission valves for turbine-driven AFW pump during a loss of power or other failure of the normal air supply. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.5.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

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 a continuous recirculation to the CST.

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 can be returned to the CST by a condensate 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.

A description of the CST is found in the FSAR, Section 9.2.6 (Ref. 1).

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, Chapters 6 and 15 (Refs. 2 and 3, respectively). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 30 minutes at MODE 3, steaming through the MSSVs, followed by a cooldown to residual heat removal (RHR) entry conditions at the design cooldown rate.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The limiting event for the condensate volume is the large feedwater line break coincident with a loss of offsite power. Single failures that also affect this event include the following:

a. Failure of the diesel generator powering the motor driven AFW pump to the unaffected steam generator (requiring additional steam to drive the remaining AFW pump turbine); and

b. Failure of the steam driven AFW pump (requiring a longer time for cooldown using only one motor driven AFW pump).

These are not usually the limiting failures in terms of consequences for these events.

The CST inventory calculation includes an allowance for a break in the AFW pump recirculation line and 30 minutes for operator action to reduce the break flow.

The CST satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat for 30 minutes 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 failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine, or before isolating AFW to a broken line.

The OPERABILITY of the CST is based on having sufficient water available to maintain the RCS in MODE 3 for 9 hours with steam discharge to the atmosphere concurrent with a total loss of offsite power. The CST minimum required water level of 164,000 gallons fulfills this requirement and bounds the design bases requirement of holding the unit in MODE 3 for 2 hours, followed by a 4 hour cooldown to RHR entry conditions of 350°F at a rate of 50°F/hour (Refs. 4 and 5).

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 is not OPERABLE, the OPERABILITY of the backup supply (Service Water System) 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 Service Water supply to the AFW pumps are OPERABLE, and that the Service Water System is capable of supplying water to the AFW pumps. The CST must be restored to OPERABLE status within 7 days, because the Service Water System does not supply the preferred quality of SG feedwater and may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 9.2.6.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. AFW – FSD A-181010.
5. CALC. BM 95-0961-001, Rev. 5, Verification of CST Sizing Basis.

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 with one shared pump and spare heat exchanger, and has isolatable nonsafety related components. Each safety related train includes a full capacity pump, heat exchanger, piping, valves, instrumentation, and a shared surge tank, with a separate section to serve each train. Each safety related train is powered from a separate bus. An open surge tank in the system ensures that sufficient net positive suction head is available. The pump in each train is automatically started on receipt of a safety injection signal, and all nonessential components are isolated.

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 135°F (Ref. 1). The Emergency Core Cooling System (ECCS) LOCA and containment OPERABILITY LOCA each model the maximum and minimum performance of the CCW System, respectively. The normal temperature of the CCW is 105°F, and, during unit cooldown to MODE 5 (T_{cold} < 200°F), a worst

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

case maximum temperature of 132.8°F is assumed. 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.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System also functions to cool the unit from RHR entry conditions (T_{cold} < 350°F), to MODE 5 (T_{cold} < 200°F), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the number of CCW and RHR trains operating. One CCW train is sufficient to remove decay heat during subsequent operations with T_{cold} < 200°F. This assumes a worst case post LOCA maximum service water temperature of 97.3°F occurring simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of 10 CFR 50.36(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 surge tank section 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.

BASES

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 note is only applicable in MODE 4. 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 overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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. The Note is applicable to CCW loads and does not include components required for CCW OPERABILITY.

Verifying the correct alignment for accessible manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. The accessibility of the CCW valves is evaluated on a case by case basis considering such things as ALARA concerns and personnel safety as well as valve enclosures or barricades blocking access to the valves. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW valves 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. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.7.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 9.2.2.

2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.8 Service Water System (SWS)

BASES

BACKGROUND

The SWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of two 50% capacity pumps, one shared 50% capacity spare pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned, except in the unlikely event of a loss of coolant accident (LOCA). The pumps are automatically started upon receipt of a safety injection signal or a loss of offsite power (LOSP) signal, and all essential valves are aligned to their post accident positions. The SWS also provides emergency makeup to the Diesel Generator Jacket Water Systems and is the backup water supply to the Auxiliary Feedwater System.

Additional information about the design and operation of the SWS, 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 SWS is the removal of decay heat from the reactor via the CCW System.

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is for one SWS train, in conjunction with the CCW System and a 100% capacity containment cooling system, 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 SWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SWS, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR), as discussed in the FSAR, Sections 5.1 and 9.2.1, (Refs. 3 and 1) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCW and RHR System trains that are operating. One SWS train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a worst case maximum post LOCA SWS Temperature of 97.3°F, which bounds the maximum normal operating SWS temperature of 95°F, occurring simultaneously with maximum heat loads on the system.

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

LCO

Two SWS 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 SWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Two pumps are OPERABLE; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the SWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SWS are determined by the systems it supports.

BASES

ACTIONS

A.1

If one SWS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SWS train could result in loss of SWS function. Required Action A.1 is modified by two Notes. The first Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources — Operating," should be entered if an inoperable SWS train results in an inoperable emergency diesel 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 SWS 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.

B.1

With one automatic turbine building isolation valve inoperable in each SWS train, the inoperable valves must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE SWS turbine building isolation valves in each train are adequate to perform the SWS non-essential load isolation function; however, the overall reliability of the function is reduced. The 72 hour Completion Time is based on the fact that the remaining OPERABLE automatic turbine building isolation valves in each SWS train ensure the SWS trains remain fully capable of performing the required safety function and the low probability of an event occurring during this time period that would require the isolation function of these valves.

C.1 and C.2

If the SWS train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 SWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SWS. The Note is applicable to SWS loads and does not include components required for SWS OPERABILITY.

Verifying the correct alignment for accessible manual, power operated, and automatic valves in the SWS flow path provides assurance that the proper flow paths exist for SWS operation. The accessibility of the SWS valves is evaluated on a case by case basis

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

considering such things as ALARA concerns and personnel safety as well as valve enclosures or barricades blocking access to the valves. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.2

This SR verifies proper automatic operation of the SWS valves on an actual or simulated Safety Injection actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR. 3.7.8.3

This SR verifies proper automatic operation of the SWS pumps on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.4

This SR requires a visual inspection be made of the ground area immediately surrounding the SWS buried piping. The performance of a visual inspection of the ground provides an indication of SWS piping integrity (leak tightness) by monitoring the surrounding ground for excessive moisture or erosion. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. FSAR, Section 9.2.1.
2. FSAR, Section 6.2.
3. FSAR, Section 5.1.
4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS, or Service Water Pond, 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 Service Water System (SWS) and the Component Cooling Water (CCW) System.

The UHS storage pond as discussed in the FSAR, Section 9.2.5 (Ref. 1) provides two principal functions: 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.

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The UHS 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. After the unit switches from injection to recirculation, 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 single active failure (e.g., single failure of a train). The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the UHS.

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

BASES

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the SWS to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature should not exceed 95°F and the level should not fall below 184 ft mean sea level during normal unit operation.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If the UHS water level or temperature are not within the required limits, the unit must be placed in a MODE in which overall plant risk is reduced To achieve this status, the unit must be placed in at least MODE 3 within 42 hours and in MODE 4 within 48 hours.

Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action A.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components,

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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 SWS pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR verifies that the UHS water level is ≥ 184 ft mean sea level.

SR 3.7.9.2

This SR verifies that the SWS 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR verifies that the water temperature at the discharge of the Service Water Pumps is ≤ 95°F.

REFERENCES

1. FSAR, Section 9.2.5.

2. Regulatory Guide 1.27.

3. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.10 CREFS

BASES

BACKGROUND

The control room provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. This environment is protected by the integrity of the Control Room Envelope (CRE) and the operation of the Control Room Emergency Filtration/Pressurization System (CREFS). The Unit 1 and 2 control room is a common room
served by a shared CREFS.

Maintaining the integrity of the CRE minimizes the infiltration of unfiltered air from areas adjacent to the CRE, thereby minimizing the possibility that the effects of a radiological challenge would result in a radiological dose which exceeds General Design Criteria (GDC) 19. It also minimizes the possibility that a fire challenge would result in a condition where the operator would be disabled or impaired such that the reactor could not be controlled from the control room or the hot shutdown panels. In addition, the CRE minimizes the possibility that a hazardous chemical challenge would result in a condition where the operator would be disabled or impaired such that the reactor could not be controlled from the control room. While the CRE provides a boundary for the CREFS to operate in, the CRE is independent from the CREFS and its OPERABILITY requirements are separate from the CREFS.

The CREFS consists of two independent, redundant trains that recirculate and filter the air in the CRE in conjunction with the CRACS, two independent, redundant trains that pressurize the control room with filtered outside air, and a CRE boundary that limits the inleakage of unfiltered air. Each CREFS train consists of a prefilter, a high efficiency particulate air (HEPA) filter, and an activated charcoal adsorber section for removal of gaseous activity (principally iodine). Each pressurization filter also contains a heater. Each train contains filter units, fans, and instrumentation which form the system.

(continued)

BASES

BACKGROUND (continued)

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, parts of which may also operate during normal unit operations in the standby mode of operation. Upon receipt of the actuating signal(s), normal air supply to the CRE is isolated, and the stream of ventilation air is recirculated through the system filter trains. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers. Operation of each pressurization train for at least 15 minutes per month, with the heaters energized, justifies their OPERABILITY. During operation, the heaters reduce moisture buildup on the HEPA filters and adsorbers. The heater is important to the effectiveness of the charcoal adsorbers.

Actuation of the CREFS places the system in the emergency recirculation mode of operation. Actuation of the system to the emergency recirculation mode of operation, closes the unfiltered outside air intake and unfiltered exhaust dampers, 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 of operation also initiates pressurization and filtered ventilation of the air supply to the CRE.

The normal outside air supply is filtered, diluted with building air from the computer rooms, and added to the control room. The air entering the CRE is continuously monitored by radiation detectors. One detector output above the setpoint will cause the control room ventilation to be isolated. The CREFS is then started manually.

(continued)

BASES

BACKGROUND (continued)

A single CREFS train provides makeup air flow and radiological dose cleanup for the control room. The CREFS operation in maintaining the control room habitable is discussed in the FSAR, Section 6.4 (Ref. 1).

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. 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 total effective dose equivalent (TEDE).

APPLICABLE SAFETY ANALYSES

The CREFS components are arranged in redundant, safety related ventilation trains. The location of components within the CRE and ducting of the CRE ensure 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).

Maintaining the integrity of the CRE limits the quantity of contaminants allowed into the CRE so that the radiological dose criteria of GDC 19 are met. The analysis of toxic gas releases demonstrates that the toxicity limits are not exceeded in the control room following a toxic chemical release. The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to maintain reactor control either from the control room or from the hot shutdown panels.

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 10 CFR 50.36(c)(2)(ii).

BASES

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 TEDE 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 the associated:

a. Fans are OPERABLE; (recirculation, filtration, Pressurization, and CRACS Fans)

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Heater is 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 DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE to be opened intermittently under administrative controls without requiring entry into Condition B for an inoperable CRE. This Note only applies to opening 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 maintenance access openings, such as hatches and test ports, the administrative control of the opening is performed by the attendant person(s) performing the maintenance. 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 integrity is indicated.

BASES

APPLICABILITY

With either unit in MODES 1, 2, 3, or 4 or during movement of irradiated fuel assemblies or during CORE ALTERATIONS, the CREFS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

During movement of irradiated fuel assemblies and CORE ALTERATIONS, the CREFS and the CRE must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1

With one CREFS train inoperable, for reasons other than an inoperable CRE boundary, action must be taken to restore it to 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 single 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 TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be 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

(continued)

BASES

ACTIONS

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

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 protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if an inoperable CREFS train or CRE cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 5). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 5, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

If two CREFS trains are inoperable in MODE 1, 2, 3, or 4, 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 Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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

During movement of irradiated fuel assemblies or during CORE ALTERATIONS, if an 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 recirculation 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 E.1 is to immediately 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 and F.2

During movement of irradiated fuel assemblies or during CORE ALTERATIONS, with two CREFS trains inoperable or with one or more CREFS trains inoperable due to an inoperable CRE boundary, action must be taken to immediately 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 accident risk. This does not preclude the movement of fuel to a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train (CREFS and Pressurization) provides an adequate check of this system. The CREFS trains are initiated from the control room with flow through the HEPA and charcoal filters. Systems must be operated for ≥ 15 minutes to demonstrate the function of the system (Ref. 3). Systems with heaters must be operated with the heaters energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 ASME N510-1989 (Ref. 4). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CREFS train starts and operates on an actual or simulated Safety Injection (SI) actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR is modified by a note which provides an exception to the requirement to meet this SR in MODES 5 and 6. This is acceptable since the automatic SI actuation function is not required in these MODES.

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 TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.4 (continued)

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. 6) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 7). 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. 8). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. FSAR, Section 6.4.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.52, Rev. 3.
4. ASME N510-1989.
5. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.
6. Regulatory Guide 1.196.
7. NEI 99-03, “Control Room Habitability Assessment,” June 2001.
8. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694)

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Air Conditioning System (CRACS)

BASES

BACKGROUND

The CRACS provides temperature control for the control room following isolation of the control room. The Unit 1 and 2 control room is a common room served by a shared CRACS.

The CRACS consists of two independent and redundant trains that provide cooling of recirculated control room air. Each train consists of cooling coils, instrumentation, and controls to provide for control room temperature control. The CRACS is a subsystem providing air temperature control for the control room.

The CRACS is a normal and emergency system. A single train will provide the required temperature control. The CRACS operation in maintaining the control room temperature is discussed in the FSAR, Section 6.4 (Ref. 1).

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. During emergency operation, the CRACS maintains the temperature at or below the continuous duty rating for equipment and instrumentation. 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 10 CFR 50.36(c)(2)(ii).

BASES

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. CRACS recirculation provides the motive force for heat removal and control room filtration cleanup in conjunction with the CREFS recirculation and filtration units. The loss of CRACS cooling on only one train will not degrade the associated train of CREFS cleanup filtration.

APPLICABILITY

With either unit in MODES 1, 2, 3, 4, or during movement of irradiated fuel assemblies or during CORE ALTERATIONS, the CRACS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

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 requiring control room isolation, the consideration that the remaining train can provide the required protection, and that alternate safety or nonsafety related cooling means are available.

(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 in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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

During movement of irradiated fuel, or during CORE ALTERATIONS, 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.

(continued)

BASES

ACTIONS

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

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

During movement of irradiated fuel assemblies, or during CORE ALTERATIONS, with two CRACS trains inoperable, action must be taken immediately to 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.

E.1

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, LCO 3.0.3 must 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 system testing. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.4.

2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.12 Penetration Room Filtration (PRF) System

BASES

BACKGROUND

The PRF System filters airborne radioactive particulates from the area of the fuel pool following a fuel handling accident or ECCS pump rooms and penetration area of the Auxiliary Building following a loss of coolant accident (LOCA).

The PRF System consists of two independent and redundant trains. Each train consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a recirculation fan and an exhaust fan. Ductwork, valves or dampers, and instrumentation also form part of the system. The heater is not credited in the analysis but serves to reduce the relative humidity of the air stream. The system initiates filtered ventilation of the spent fuel pool room following receipt of a high radiation signal or a low air flow signal from the normal ventilation system. The system initiates filtered ventilation of the ECCS pump rooms and penetration area following receipt of a containment isolation actuation system (CIAS) Phase B signal and manual isolation of the spent fuel pool room.

The PRF System is a standby system normally aligned to filter the spent fuel pool room. During emergency operation the PRF System filters the spent fuel pool room or the ECCS pump rooms and penetration area with fan actuation signals and damper re-alignments to the ECCS pump rooms and penetration area (to support each respective area). Upon receipt of the actuating Engineering Safety Feature Actuation System signal for post LOCA conditions or upon receipt of a high radiation signal or a low air flow signal from the normal spent fuel pool room ventilation system, the PRF fans are started and the ventilation air stream discharges through the system filter trains.

The PRF System is discussed in the FSAR, Sections 6.2.3, 9.4.2, and 15.4 (Refs. 1, 2, and 3, respectively) which detail the post accident, atmospheric cleanup functions. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers.

BASES

APPLICABLE SAFETY ANALYSES

The PRF System design basis is established by the consequences of the limiting Design Basis Accidents (DBAs), which are a fuel handling accident and a large break loss of coolant accident (LOCA). The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged. The analysis of the LOCA assumes that radioactive materials leaked from the Emergency Core Cooling System (ECCS) are filtered and adsorbed by the PRF System. The PRF System also functions following a small break LOCA with a Phase B signal or manual operator actuation 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 steam packing. The DBA analysis of the fuel handling accident and LOCA assumes that only one train of the PRF System is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the one remaining train of this filtration system. The amount of fission products available for release from the spent fuel pool room is determined for a fuel handling accident and ECCS leakage for a LOCA. The analysis of the effects and consequences of a fuel handling accident and a LOCA are presented in Reference 3. The assumptions and the analysis for the fuel handling accident follow the guidance provided in Regulatory Guide 1.183 (Ref. 4).

The PRF System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the PRF System are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train, coincident with a loss of offsite power. During movement of irradiated fuel in the spent fuel pool room both trains of PRF are required to be aligned to the spent fuel pool room. Total system failure could result in the atmospheric release from the spent fuel pool room or ECCS pump rooms exceeding 25% of the 10 CFR 50.67 (Ref. 5) limits in the event of a fuel handling accident or LOCA respectively.

The PRF System is considered OPERABLE when the individual components necessary to control exposure in the spent fuel pool room, ECCS pump rooms, and penetration area are OPERABLE in both trains. A PRF train is considered OPERABLE when its associated:

a. Recirculation and exhaust fans are OPERABLE;

(continued)

LCO (continued)

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

The LCO is modified by a Note allowing the PRF or spent fuel pool room (SFPR) boundary to be opened intermittently under administrative controls without requiring entry into Conditions B or E for an inoperable pressure boundary. 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, such as hatches and inspection ports, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for PRF or SFPR ventilation actuation is indicated. Breaches that would prevent successful completion of SR 3.7.12.6 render the SFPR boundary inoperable. When the SFPR boundary is inoperable, Condition E will prohibit movement of irradiated fuel. For loads other than irradiated fuel, administrative controls will prevent movement of loads over irradiated fuel unless adequate decay time for the irradiated fuel has elapsed such that occurrence of a fuel handling accident without air filtration will not exceed dose limits. Calculations show that a decay time of 676 hours is sufficient.

APPLICABILITY

In MODE 1, 2, 3, or 4, the PRF System is required to be OPERABLE to provide fission product removal associated with ECCS leaks due to a LOCA.

In MODE 5 or 6, the PRF System is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

During movement of irradiated fuel in the spent fuel pool area, two trains of PRF are required to be OPERABLE and aligned to the spent fuel pool room to alleviate the consequences of a fuel handling accident.

ACTIONS

A.1

With one PRF train inoperable, action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the PRF function. The 7 day Completion Time is based on the risk from an event occurring requiring the inoperable PRF train, and the remaining PRF train providing the required protection.

(continued)

BASES

ACTIONS (continued)

B.1

If the PRF system is inoperable due to a penetration room boundary being inoperable in MODE 1, 2, 3, or 4, the PRF trains cannot perform their intended functions. Actions must be taken to restore the PRF boundary within 24 hours. During the period the PRF boundary is inoperable, appropriate compensatory measures (consistent with the intent of GDC 19) should be utilized to protect control room operators from potential radiological hazards. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24 hour Completion Time for the post LOCA mode of operation is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. It provides a reasonable time to diagnose, plan and possibly repair, and test most problems with the PRF boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, when Required Action A.1 or B.1 cannot be completed within the associated Completion Time, or when both PRF trains are inoperable, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in MODE 3 within 6 hours, and in MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 7). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 7, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

D.1 and D.2

When Required Action A.1 cannot be completed within the required Completion Time, during movement of irradiated fuel assemblies in the spent fuel pool room, the OPERABLE PRF train must be started immediately or fuel movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing system operation will occur, and that any active failure will be readily detected.

If the system is not placed in operation, this action requires suspension of fuel movement, which precludes a fuel handling accident. This does not preclude the movement of fuel assemblies to a safe position.

E.1

When two trains of the PRF System are inoperable during movement of irradiated fuel assemblies in the spent fuel pool room, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the spent fuel pool room. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

During movement of irradiated fuel in the spent fuel pool room, the two PRF trains are required to be aligned to the spent fuel pool room. When moving irradiated fuel, periodic verification of the PRF system alignment is required. During movement of irradiated fuel the potential exists for a fuel handling accident. Verification of the PRF train alignment when moving irradiated fuel provides assurance the correct system alignment is maintained to support the assumptions of the fuel handling accident analysis regarding the OPERABILITY of the PRF System.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This surveillance is modified by a note which clarifies that the surveillance need only be performed during the movement of irradiated fuel in the spent fuel pool room.

SR 3.7.12.2

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system. This Surveillance requires that the operation of the PRF System be verified in the applicable alignment (post LOCA and/or refueling accident). The surveillance is applied separately to each operating mode of the PRF System as required by plant conditions. In MODE 1-4, operational testing in the post LOCA alignment is required to verify the capability of the system to perform in this capacity. Operational testing of the PRF System in the refueling accident alignment is only required to be performed to support the movement of irradiated fuel in the spent fuel pool storage room (when the potential exists for a fuel handling accident).

Systems that do not credit the operation of heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The system is initiated from the control room with flow through the HEPA and charcoal filters. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.3

This SR verifies that the required PRF System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The PRF System filter tests are in accordance with ASME N510-1989 (Ref. 6). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.4

This SR verifies that each PRF train starts and operates on an actual or simulated Phase B actuation signal. In addition, the normal spent fuel pool ventilation system must be verified to isolate on an actual or simulated spent fuel pool ventilation low differential pressure signal and on an actual or simulated spent fuel pool high radiation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.5

This SR verifies the integrity of the ECCS pump rooms and penetration area boundary. The ability of the boundary to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the PRF System. During the post-LOCA mode of operation, the PRF System is designed to maintain a slight negative pressure in the ECCS pump rooms and penetration area boundary, to prevent unfiltered LEAKAGE. The PRF System is designed to maintain ≤ -0.125 inches water gauge with respect to adjacent area pressure (as measured by the ΔP between the PRF mechanical equipment room and the RHR Heat Exchanger Room) at a flow rate of ≤ 5,500 cfm.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.6

During the fuel handling mode of operation, the PRF is designed to maintain a slightly negative pressure in the spent fuel pool room with respect to atmospheric pressure and surrounding areas at a flow rate of ≤ 5,500 cfm, to prevent unfiltered leakage. The slightly negative pressure is verified by using a non-rigorous method that yields some observable identification of the slightly negative pressure. Examples of non-rigorous methods are smoke sticks, hand held differential pressure indicators, or other measurement devices that do not provide for an absolute measurement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.2.3.
2. FSAR, Section 9.4.2.

(continued)

BASES

REFERENCES (continued)

3. FSAR, Sections 15.4.1 and 15.4.5.
4. Regulatory Guide 1.183.
5. 10 CFR 50.67.
6. ASME N510-1989.
7. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Pool Water Level

BASES

BACKGROUND	The minimum water level in the fuel storage pool 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. A general description of the fuel storage pool design is given in the 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 15.4.5 (Ref. 3).
APPLICABLE SAFETY ANALYSES	The minimum water level in the fuel storage pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 4). The resultant 2 hour dose per person at the exclusion area boundary is well within the 10 CFR 50.67 (Ref. 5) limits. According to Reference 4, there is 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 between the top of the fuel bundle and the surface, indicated by the width of the bundle. To offset this small nonconservatism, the analysis 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 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The fuel storage pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in 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 fuel storage pool.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage pool 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 3.7.13.1

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.13.1 (continued) During refueling operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked in accordance with SR 3.9.6.1 (refueling cavity water level verification).
REFERENCES	1. FSAR, Section 9.1.2. 2. FSAR, Section 9.1.3. 3. FSAR, Section 15.4.5. 4. Regulatory Guide 1.183, Rev. 0. 5. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.14 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

Fuel assemblies are stored in high density racks. The spent fuel storage racks contain storage locations for 1407 fuel assemblies. Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 can be stored in any location in the spent fuel storage pool provided the fuel burnup-enrichment combinations are within the limits specified in Figure 3.7.15-1 of the Technical Specifications. Fuel assemblies that do not meet the burnup-enrichment combination of Figure 3.7.15-1 may be stored in the spent fuel storage pool in accordance with the patterns described in Figures 4.3.1-1 through 4.3.1-5. The acceptable storage configurations are based on the “Westinghouse Spent Fuel Rack Criticality Analysis Methodology”, WCAP-14416-NP-A, Rev. 1, (Ref. 4) as implemented in the “Farley Units 1 and 2 Spent Fuel Rack Criticality Analysis Using Soluble Boron Credit,” CAA-97-138, Rev. 1 (Ref. 7).

This methodology ensures that the spent fuel pool storage rack multiplication factor, K_{eff}, is less than or equal to 0.95, as recommended by ANSI 57.2-1983 (Ref. 3) and NRC Guidance (Refs. 1, 2, and 6). A storage configuration is defined using K_{eff} calculations to ensure that K_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including tolerances and uncertainties. Soluble boron credit is then used to maintain K_{eff} less than or equal to 0.95. A spent fuel pool boron concentration of 400 ppm will ensure that K_{eff} will be less than or equal to 0.95 for all analyzed combinations of storage patterns, enrichments, and burnups. The treatment of reactivity equivalencing uncertainties, as well as the calculation of postulated accidents crediting soluble boron is described in Ref.4.

The above methodology was used to evaluate storage of Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 in the FNP spent fuel storage pool. The resulting enrichment and burnup limits are shown in Figure 3.7.15-1. Checkerboard loading patterns are defined to allow storage of fuel assemblies that are not within the acceptable burnup domain of Figure 3.7.15-1. These storage requirements are shown in Technical Specification Figures 4.3.1-1 through 4.3.1-5. A

(continued)

BASES

BACKGROUND (continued)	spent fuel pool boron concentration of 2000 ppm ensures that no credible boron dilution event will result in a K_{eff} greater than 0.95. Eleven damaged Westinghouse 17X17 fuel assemblies can be stored in the Unit 1 spent fuel storage pool in the 12 storage cell configuration shown in Technical Specification Figure 4.3.1-6. The 11 fuel assemblies contain a nominal enrichment of 3.0 weight percent U-235.
APPLICABLE SAFETY ANALYSES	Three accidents can be postulated for each storage configuration which could increase reactivity beyond the analyzed condition. The three postulated accidents include a loss of the spent fuel pool cooling system, dropping a fuel assembly into an already loaded storage cell, and the misloading of a fuel assembly into a cell for which the restrictions on location, enrichment, or burnup are not satisfied. An increase in the temperature of the water passing through the stored fuel assemblies causes a decrease in water density which would normally result in an addition of negative reactivity. However, since Boraflex is not considered to be present in the criticality analysis, and the spent fuel pool water contains a high concentration of boron, a density decrease results in a positive reactivity addition. The effect of an increase in reactivity due to an increase in temperature is bounded by the misload accident. In the case of a fuel assembly dropped into an already loaded storage cell, the upward axial leakage of that cell will be reduced. However, the overall effect on the storage rack activity would be insignificant, since only the upward axial leakage of a single cell is minimized. In addition, the neutronic coupling between the dropped fuel assembly and the already loaded assembly will be low due to a several inch separation of the active fuel regions due to the fuel assembly bottom nozzle. The effects of this accident are also bounded by the misload accident. The fuel assembly misloading accident involves the placement of a fuel assembly into a storage location for which the requirements on location, enrichment, or burnup are not met. This misload would result in a positive reactivity addition increasing K_{eff} toward 0.95. The amount of soluble boron required to compensate for the positive reactivity added is 850 ppm, which is well below the LCO limit of 2000 ppm.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

A spent fuel pool boron dilution evaluation determined that the volume of water necessary to dilute the spent fuel pool from the LCO limit of 2000 ppm to 400 ppm (the boron concentration required to maintain K_{eff} less than or equal to 0.95) is approximately 480,000 gallons. A spent fuel pool dilution of this volume is not a credible event, since it would require this large volume of water to be transferred from a source to the spent fuel pool, ultimately overflowing the pool. This event would be detected and terminated by plant personnel prior to exceeding a K_{eff} of 0.95.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(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 specified boron concentration of 2000 ppm ensures that the spent fuel pool K_{eff} will remain less than or equal to 0.95 due to a postulated fuel assembly misload accident (850 ppm) or boron dilution event (400 ppm).

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool.

ACTIONS

A.1 and A.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

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 is most efficiently achieved by immediately suspending the movement of fuel assemblies. Action is also initiated to restore the concentration of boron simultaneously with suspending movement of fuel assemblies.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 3.7.14.1

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USNRC Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition, NUREG-0800, June, 1987.

2. USNRC Spent Fuel Storage Facility Design Bases (for Comment) Proposed Revision 2, 1981.

3. ANS, "Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations," ANSI/ANS-57.2-1983.

4. WCAP-14416-NP-A, Rev. 1, "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," November, 1996.

5. FSAR, Section 4.3.2.7.2.

6. NRC, Letter to all Power Reactor Licensees from B.K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

7. "Farley Units 1 and 2 Spent Fuel Rack Criticality Analysis Using Soluble Boron Credit," CAA-97-138, Rev. 1.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Assembly Storage

BASES

BACKGROUND

Fuel assemblies are stored in high density racks. The spent fuel storage racks contain storage locations for 1407 fuel assemblies. Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 can be stored in any location in the spent fuel storage pool provided the fuel burnup-enrichment combinations are within the limits specified in Figure 3.7.15-1 of the Technical Specifications. Fuel assemblies that do not meet the burnup-enrichment combination of Figure 3.7.15-1 may be stored in the spent fuel storage pool in accordance with the patterns described in Figures 4.3.1-1 through 4.3.1-5. The acceptable storage configurations are based on the "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," WCAP-14416-NP-A, Rev. 1, (Ref. 1) as implemented in "Farley Units 1 and 2 Spent Fuel Rack Criticality Analysis Using Soluble Boron Credit," CAA-97-138, Rev. 1 (Ref. 2).

The following storage configurations and enrichment limits were evaluated in the spent fuel rack criticality analysis:

Westinghouse 17X17 fuel assemblies with nominal enrichments less than or equal to 2.15 weight percent U-235 can be stored in any cell location as shown if Figure 4.3.1-2. Fuel assemblies with initial nominal enrichments greater than these limits must satisfy a minimum burnup requirement as shown in Figure 3.7.15-1.

Westinghouse 17X17 fuel assemblies with nominal enrichments less than or equal to 5.0 weight percent U-235 can be stored in a 2 out of 4 checkerboard arrangement as shown in Figure 4.3.1-2. In the 2 out of 4 checkerboard storage arrangement, 2 fuel assemblies can be stored corner adjacent with empty storage cells.

Westinghouse 17X17 fuel assemblies can be stored in a burned/fresh checkerboard arrangement of a 2X2 matrix of storage cells as shown in Figure 4.3.1-2. In the burned/fresh 2X2 checkerboard arrangement, three of the fuel assemblies must have an initial nominal enrichment less than or equal to 1.6 weight percent U-235, or satisfy a minimum burnup requirement for higher initial enrichments as shown in Figure 4.3.1-1.

(continued)

BASES

BACKGROUND (continued)

The fourth fuel assembly must have an initial nominal enrichment less than or equal to 3.9 weight percent U-235, or satisfy a minimum Integral Fuel Burnable Absorber requirement for higher initial enrichments to maintain the reference fuel assembly K_∞ less than or equal to 1.455 at 68°F.

Eleven damaged Westinghouse 17X17 fuel assemblies can be stored in the Unit 1 spent fuel storage pool in a 12 storage cell configuration surrounded by empty cells as shown in Technical Specification Figure 4.3.1-6. The 11 fuel assemblies contain a nominal enrichment of 3.0 weight percent U-235.

APPLICABLE SAFETY ANALYSES

Three accidents can be postulated for each storage configuration which could increase reactivity beyond the analyzed condition. The three postulated accidents include a loss of the spent fuel pool cooling system, dropping a fuel assembly into an already loaded storage cell, and the misloading of a fuel assembly into a cell for which the restrictions on location, enrichment, or burnup are not satisfied.

An increase in the temperature of the water passing through the stored fuel assemblies causes a decrease in water density which would normally result in an addition of negative reactivity. However, since Boraflex is not considered to be present in the criticality analysis, and the spent fuel pool water contains a high concentration of boron, a density decrease results in a positive reactivity addition. The effect of an increase in reactivity due to an increase in temperature is bounded by the misload accident.

In the case of a fuel assembly dropped into an already loaded storage cell, the upward axial leakage of that cell will be reduced. However, the overall effect on the storage rack activity would be insignificant, since only the upward axial leakage of a single cell is minimized. In addition, the neutronic coupling between the dropped fuel assembly and the already loaded assembly will be low due to a several inch separation of the active fuel regions due to the fuel assembly bottom nozzle. The effects of this accident are also bounded by the misload accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The fuel assembly misloading accident involves the placement of a fuel assembly into a storage location for which the requirements on location, enrichment, or burnup are not met. This misload would result in a positive reactivity addition increasing K_{eff} toward 0.95. The amount of soluble boron required to compensate for the positive reactivity added is 850 ppm, which is well below the LCO limit of 2000 ppm. The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool ensure the K_{eff} of the spent fuel storage pool will always remain < 0.95, assuming the pool to be flooded with borated water. The combination of initial enrichment and burnup are specified in Figure 3.7.15-1 for the All Cell Storage Configuration. Other acceptable enrichment, burnup, and checkerboard storage configurations are specified in Figures 4.3.1-1 through 4.3.1-6.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the spent fuel storage pool.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the configuration of fuel assemblies stored in the spent fuel storage pool is not in accordance with the acceptable combination of initial enrichments, burnup, and storage configurations, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figure 3.7.15-1 or Specification 4.3.1.1. 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies by administrative means (e.g., Core Loading Plan, Tote computer code output or TrackWorks program) that the initial enrichment and burnup of the fuel assembly is within the acceptable burnup domain of Figure 3.7.15-1. For fuel assemblies in the unacceptable range of Figure 3.7.15-1, performance of this SR will also ensure compliance with Specification 4.3.1.1.

The frequency of within 7 days following the relocation or addition of fuel assemblies to the spent fuel storage pool ensures that fuel assemblies are stored within the configuration analyzed in the spent fuel rack criticality analysis. This surveillance would be performed after all of the fuel handling is completed during a refueling outage, or new fuel assemblies are placed into the spent fuel pool.

This SR does not have to be performed following interruptions in fuel handling during defined fuel movements as described above (i.e., it is only required after all fuel movement associated with refueling operations is completed) or if only certain fuel assemblies are relocated to different storage locations within the pool (only the moved assemblies must be verified).

The 7 day allowance for completion of this Surveillance provides adequate time for completion of a spent fuel pool inventory verification while minimizing the time that a fuel assembly could be misloaded during a refueling or the placement of new fuel assemblies into the spent fuel pool. The boron concentration required by Specification 3.7.14 ensures that the spent fuel rack K_{eff} remains within limits until the spent fuel pool inventory verification is performed.

REFERENCES

1. WCAP-14416-NP-A, Rev. 1, "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," November, 1996.

2. "Farley Units 1 and 2 Spent Fuel Rack Criticality Analysis Using Soluble Boron Credit," CAA-97-138, Rev. 1.

B 3.7 PLANT SYSTEMS

B 3.7.16 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 450 gallons per day tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 0.5 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).

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the site boundary would be within the limits of 10 CFR 20.1001– 20.2402 if the main steam safety valves (MSSVs) and Atmospheric Relief Valves (ARVs) are open for 2 hours following a trip from full power.

Operating at the allowable limits results in a 2 hour exclusion area boundary exposure well within the 10 CFR 50.67 (Ref. 1) limits.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 exclusion area boundary limits (Ref. 1). 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 and steam generator atmospheric relief valves (ARVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown. In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ARVs during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure. Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	As indicated in the Applicable Safety Analyses, the specific activity 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 in the steam generators 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.

BASES

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 3.7.16.1 This SR verifies that the secondary specific activity in the steam generators 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 releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50.67. 2. FSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.17 Cask Storage Area Boron Concentration — Cask Loading Operations

BASES

BACKGROUND

The cask storage area is connected to the spent fuel pool when the spent fuel transfer canal gate and the cask storage area gate are removed and is used to facilitate cask loading operations. The spent fuel cask contains storage locations for 32 fuel assemblies. Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 can be stored in the spent fuel cask provided the fuel burnup-enrichment combinations are within the limits specified in Figure 3.7.18-1 of the Technical Specifications. Westinghouse Calculation Note CN-CRIT-207, "MPC-32 Criticality Analysis for the J. M. Farley Nuclear Plant," (Ref. 4) provides the basis for acceptability to conduct cask loading operations in the cask storage area.

The above methodology ensures that the spent fuel cask multiplication factor, K_{eff}, is less than or equal to 0.95, as recommended by ANSI 57.2-1983 (Ref. 3) and NRC Guidance (Refs. 1, 2, and 6). A storage configuration is defined using K_{eff} calculations to ensure that K_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including tolerances and uncertainties. Soluble boron credit is then used to maintain K_{eff} less than or equal to 0.95. The treatment of reactivity uncertainties, as well as the calculation of postulated accidents crediting soluble boron is described in Ref.4.

The above methodology was used to evaluate cask loading of Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 in the spent fuel cask during loading operations in the cask storage area. The resulting enrichment and burnup limits are shown in Figure 3.7.18-1.

A cask storage area boron concentration of 2000 ppm ensures that no credible boron dilution event will result in a K_{eff} greater than 0.95.

BASES

APPLICABLE SAFETY ANALYSES

The soluble boron concentration required to maintain $K_{eff} \leq 0.95$ under accident conditions was determined by evaluating all credible events which increase the K_{eff} value of the spent fuel cask (Ref. 4). The accident event which produces the largest increase in the spent fuel cask K_{eff} value is employed to determine the required soluble boron concentration necessary to mitigate this and all less severe accident events. The list of accident cases considered includes:

- Dropped fresh fuel assembly on top of the spent fuel cask,
- Misloaded fresh fuel assembly outside of the spent fuel cask,
- Spent fuel cask assembly-to-assembly pitch reduction due to seismic event,
- Spent fuel cask water temperature greater than 180 °F, and
- Misloaded fresh fuel assembly into a spent fuel cask location.

It is possible to drop a fresh fuel assembly on top, or immediately outside, of the spent fuel cask. In this case, the physical separation (approximately 20 inches) between the fuel assemblies loaded inside the spent fuel cask and the assembly lying on top or outside is sufficient to neutronically decouple the accident. This accident will produce a very small positive reactivity increase. This small increase will not be as limiting as the reactivity increase associated with a fuel misloading event inside the spent fuel cask.

For the accident due to a seismic event, the assembly-to-assembly pitch is reduced such that the condition can be approximated by that of the off-center assembly case (performed as part of the uncertainty analysis). An increase of 0.00304 ΔK_{eff} (not accounting for uncertainties) is determined for this case, and this is significantly less than the reactivity increase due to a fuel misloading event inside the spent fuel cask.

The nominal water temperature range addressed for the spent fuel cask in this analysis is 50 °F to 180 °F. It is possible to increase the spent fuel cask water temperature above 180 °F. However, an increase to 180 °F is determined to actually decrease reactivity (as part of the uncertainty analysis). Based on the response of the reactivity to increasing temperature up to 180 °F, any increase in reactivity above 180 °F will be minimal as compared to the fuel mishandling event. Therefore, at higher temperatures, the fuel mishandling event remains limiting.

The fuel assembly misloading accident represents the most severe postulated event for reactivity increase in K_{eff} and involves the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

placement of a fresh Westinghouse Optimized Fuel Assembly (OFA) fuel assembly enriched to 5.0 weight percent (containing no burnable poisons) into a cask center cell storage location. This misload would result in a positive reactivity addition increasing K_{eff} toward 0.95. The amount of soluble boron required to compensate for the positive reactivity added is 659 ppm, which is well below the LCO limit of 2000 ppm.

As described in Bases for LCO 3.7.14, a spent fuel pool boron dilution evaluation determined that the volume of water necessary to dilute the spent fuel pool from the LCO limit of 2000 ppm to 400 ppm (the boron concentration required to maintain K_{eff} less than or equal to 0.95) is approximately 480,000 gallons. A spent fuel pool dilution of this volume is not a credible event, since it would require this large volume of water to be transferred from a source to the spent fuel pool, ultimately overflowing the pool. This event would be detected and terminated by plant personnel prior to exceeding a K_{eff} of 0.95.

During cask loading operations, the active volume of the spent fuel pool will be increased by the volume of the transfer canal and the cask storage area. This has the effect of reducing the rate of dilution of the pool, therefore, the dilution evaluation for the spent fuel pool remains bounding for cask loading operations.

The concentration of dissolved boron in the cask storage area satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The cask storage area 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 specified boron concentration of 2000 ppm ensures that the spent fuel cask K_{eff} will remain less than or equal to 0.95 due to a postulated fuel assembly misload accident (659 ppm) or boron dilution event (400 ppm).

The LCO is modified by a note that requires the spent fuel transfer canal gate and the cask storage area gate to both be open during cask loading operations except during the brief period when moving the spent fuel cask into or out of the cask storage area. This is to ensure that the boron dilution evaluation for the spent fuel pool remains bounding for cask loading operations.

BASES

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the cask storage area of the spent fuel pool.

ACTIONS

A.1 and A.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the fuel storage pool (including the transfer canal and cask storage area) is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. Action is also initiated to restore the concentration of boron simultaneously with suspending movement of fuel assemblies.

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 3.7.17.1

The boron concentration in the spent fuel cask storage area water must be verified to be within limit within four hours prior to entering the Applicability of the LCO. For loading operations, this means within four hours of loading the first fuel assembly into the cask.

For unloading operations, this means verifying the concentration of the borated water source to be used to re-flood the spent fuel cask within four hours of commencing re-flooding operations. This ensures that when the LCO is applicable (upon introducing water into the spent fuel cask), the LCO will be met.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

When both the transfer canal gate and the cask storage area gate are open, the boron concentration measurement may be performed by sampling in accordance with SR 3.7.14.1. When at least one gate is closed, the sample is to be taken in the cask storage area.

BASES

REFERENCES

1. USNRC Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition, NUREG-0800, June, 1987.

2. USNRC Spent Fuel Storage Facility Design Bases (for Comment) Proposed Revision 2, 1981.

3. ANS, "Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations," ANSI/ANS-57.2-1983.

4. "MPC-32 Criticality Analysis for the J. M. Farley Nuclear Plant," CN-CRIT-207.

5. FSAR, Section 4.3.2.7.2.3.

6. NRC, Letter to all Power Reactor Licensees from B.K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

B 3.7 PLANT SYSTEMS

B 3.7.18 Spent Fuel Assembly Storage — Cask Loading Operations

BASES

BACKGROUND

The cask storage area is connected to the spent fuel pool when the spent fuel transfer canal gate and the cask storage area gate are removed and is used to facilitate cask loading operations. The spent fuel cask contains storage locations for 32 fuel assemblies. Westinghouse 17X17 fuel assemblies with initial enrichments less than or equal to 5.0 weight percent U-235 can be stored in the spent fuel cask provided the fuel burnup-enrichment combinations are within the limits specified in Figure 3.7.18-1 of the Technical Specifications. Westinghouse Calculation Note CN-CRIT-207, "MPC-32 Criticality Analysis for the J. M. Farley Nuclear Plant," (Ref. 1) provides the basis for acceptability to conduct cask loading operations in the cask storage area assuming a postulated boron dilution event.

Westinghouse 17X17 fuel assemblies with nominal enrichments less than or equal to 5.0 weight percent U-235 can be stored in the spent fuel cask. The fuel assemblies must satisfy the minimum burnup requirement as shown in Figure 3.7.18-1.

APPLICABLE SAFETY ANALYSES

The soluble boron concentration required to maintain $K_{eff} \leq 0.95$ under accident conditions was determined by evaluating all credible events which increase the K_{eff} value of the spent fuel cask (Ref. 1). The accident event which produces the largest increase in the spent fuel cask K_{eff} value is employed to determine the required soluble boron concentration necessary to mitigate this and all less severe accident events. The list of accident cases considered includes:

- Dropped fresh fuel assembly on top of the spent fuel cask,
- Misloaded fresh fuel assembly outside of the spent fuel cask,
- Spent fuel cask assembly-to-assembly pitch reduction due to seismic event,
- Spent fuel cask water temperature greater than 180 °F, and
- Misloaded fresh fuel assembly into a spent fuel cask location.

It is possible to drop a fresh fuel assembly on top, or immediately outside, of the spent fuel cask. In this case, the physical separation (approximately 20 inches) between the fuel assemblies loaded inside the spent fuel cask and the assembly lying on top or outside is

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	sufficient to neutronically decouple the accident. This accident will produce a very small positive reactivity increase. This small increase will not be as limiting as the reactivity increase associated with a fuel misloading event inside the spent fuel cask. For the accident due to a seismic event, the assembly-to-assembly pitch is reduced such that the condition can be approximated by that of the off-center assembly case (performed as part of the uncertainty analysis). An increase of 0.00304 ΔK_{eff} (not accounting for uncertainties) is determined for this case, and this is significantly less than the reactivity increase due to a fuel misloading event inside the spent fuel cask. The nominal water temperature range addressed for the spent fuel cask in this analysis is 50 °F to 180 °F. It is possible to increase the spent fuel cask water temperature above 180 °F. However, an increase to 180 °F is determined to actually decrease reactivity (as part of the uncertainty analysis). Based on the response of the reactivity to increasing temperature up to 180 °F, any increase in reactivity above 180 °F will be minimal as compared to the fuel mishandling event. Therefore, at higher temperatures, the fuel mishandling event remains limiting. The fuel assembly misloading accident represents the most severe postulated event for reactivity increase in K_{eff} and involves the placement of a fresh Westinghouse Optimized Fuel Assembly (OFA) fuel assembly enriched to 5.0 weight percent (containing no burnable poisons) into a cask center cell storage location. This misload would result in a positive reactivity addition increasing K_{eff} toward 0.95. The amount of soluble boron required to compensate for the positive reactivity added is 659 ppm, which is well below the LCO limit of 2000 ppm. The configuration of fuel assemblies in the cask storage area satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The K_{eff} of the spent fuel cask will always remain ≤ 0.95, assuming the spent fuel pool, including the cask storage area, to be flooded with borated water. The combination of initial enrichment and burnup are specified in Figure 3.7.18-1 for the Cask Storage Configuration.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the cask storage area of the spent fuel pool.

BASES

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the configuration of fuel assemblies stored in the cask storage area is not in accordance with the acceptable combination of initial enrichments and burnup, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figure 3.7.18-1.

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 3.7.18.1

This SR verifies by administrative means (e.g., Cask Loading Plan, Tote computer code output or TrackWorks program) that the initial enrichment and burnup of the fuel assembly is within the acceptable burnup domain of Figure 3.7.18-1. This surveillance must be completed prior to placing any fuel assembly in the spent fuel cask.

REFERENCES

1. "MPC-32 Criticality Analysis for the J. M. Farley Nuclear Plant," CN-CRIT-207.

B 3.7 PLANT SYSTEMS

B 3.7.19 Engineered Safety Feature (ESF) Room Coolers

BASES

BACKGROUND

Room cooling for Technical Specifications (TS) ESF equipment is provided by the ESF Room Coolers. The Room Coolers are divided into subsystems and each subsystem has two 100 % capacity trains. The ESF Room Cooler subsystems are:

Motor Driven Auxiliary Feedwater (MDAFW) Pump Rooms
Charging Pump Rooms
Containment Spray (CS) Pump Rooms
Residual Heat Removal (RHR) Pump Rooms
Component Cooling Water (CCW) Pumps Room
Auxiliary Building DC Switchgear / Battery Charger Rooms
Load Control Center (LCC) Rooms (LCC D and E Rooms)

The ESF Room Coolers are considered support equipment for ESF equipment in these rooms with the exception of the CCW Pumps Room (see discussion under Applicable Safety Analysis).

Each ESF Room Cooler subsystem consists of two 100 % capacity trains which include cooling coils, electric fans, piping, manual valves, and instrumentation. The ESF Room Coolers provide cooling to ESF equipment rooms during accident, and post accident conditions. The ESF Room Coolers supplement the normal Heating / Ventilation and Air Conditioning (HVAC) system in cooling certain rooms during normal operations. The Service Water system supplies water to the cooling coils for ESF Room Coolers.

The ESF Room Coolers are designed to maintain the ambient air temperature within the continuous-duty rating of the ESF equipment served by the system. Each equipment room is cooled by a fan cooler that is powered from the same ESF train as that associated with the equipment in the room. Thus, a power failure or other single failure to one cooling system train will not prevent the cooling of redundant ESF equipment in the other train.

In addition to a manual start / run capability, automatic cooling of ESF equipment rooms is initiated by two possible signals: high room temperature or an equipment running signal, depending on the Room Cooler.

The ESF Room Coolers are seismic category I and remain operational during and after a safe shutdown earthquake.

APPLICABLE SAFETY ANALYSES

The design basis of the ESF Room Coolers is to maintain air temperatures as required in rooms containing safety-related equipment during and after a design basis loss of coolant accident (LOCA) with a loss of offsite power.

The ESF Room Coolers are required to start when the associated equipment is running or based on the temperature of the associated equipment room. Each Room Cooler Fan can also be placed in Run mode locally. With the Room Cooler in the Run mode, the automatic starting functions are being met and the Room Cooler is considered OPERABLE. The system is designed to perform its function with a single failure of any active component, assuming the loss of offsite power. One train of an ESF Room Cooler subsystem provides 100 % of the required cooling for the associated ESF equipment.

Analyses were performed to determine how room temperature was affected during a design basis accident (DBA) event. The DBA heat loads and service water temperature were used and the resulting room temperatures were compared against the continuous-duty rating of the ESF TS equipment in the rooms. The analyses showed that the Room Cooler arrangement at FNP is effective in mitigating the consequences of a DBA.

This TS requires ESF Room Coolers to be OPERABLE when associated ESF equipment is required to be OPERABLE. With the condition of one required ESF Room Cooler subsystem train inoperable, the required action is to restore the Room Cooler to OPERABLE status within 72 hours. If the Room Cooler cannot be restored to OPERABLE status within 72 hours or if two trains of an ESF Room Cooler subsystem are inoperable, the actions will require the plant to be placed in Mode 3 within 6 hours and Mode 5 within 36 hours.

The major maintenance activities that require a significant amount of time are repair or replacement of the fan motor or cooling coils. This is based on the time required to access the Room Cooler motor, remove the motor from the cooler housing, order and receive replacement parts, repair the motor, install the motor back in the cooler housing, and test the cooler. Access to these Room Coolers is limited and requires significant rigging to remove and install the housing and motor. Similarly, repair or replacement of the cooler coil is also limited by available space and rigging requirements. Based on the history of maintenance activities that have been required on the plant Room Coolers, a Completion Time of 72 hours is reasonable and allows maintenance activities to be completed without requiring unnecessary plant transients.

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APPLICABLE SAFETY ANALYSES (continued)

MDAFW, Charging, CS and RHR Pump Rooms Subsystems

In accordance with TS, when both trains of these ESF pumps are required to be OPERABLE, a single train of each ESF pump system is allowed to be out of service for up to 72 hours before shutdown actions are required. This Completion Time is consistent with the Completion Time in this TS for ESF Room Coolers and will allow sufficient time for maintenance or repair activities to be completed without requiring unnecessary plant transients. In the event of a design basis accident during the 72 hour Completion Time, the opposite non-affected train ESF Pump and Room Cooler are available to support the ESF equipment for mitigation of the accident.

CCW Pumps Room Subsystem

Calculations show that with the safety-related Room Coolers out of service under accident conditions, temperature of the CCW pumps room will not exceed the continuous-duty rating of the ESF TS equipment in the room. Thus the associated safety-related Room Coolers are not considered support equipment for the ESF TS equipment in this room and as such, are not required for the ESF TS equipment in the room to remain OPERABLE. Therefore, other than for pressure boundary integrity, the safety-related Room Coolers for the CCW Pumps Room are not considered a required ESF Room Cooler subsystem.

Auxiliary Building DC Switchgear / Battery Charger Rooms Subsystem

FNP has three Room Coolers and three battery chargers servicing two trains of Auxiliary Building DC Switchgear / Battery Charger. Analysis has determined that aligning the swing battery charger and Room Cooler power supply, cooling water supply and fan discharge (by opening the room door), to the switchgear train room with an inoperable Room Cooler will provide adequate cooling to the switchgear / battery charger room. In the event that a connecting door is opened to align the fan discharge into the affected switchgear train room, plant procedures ensure that the door is secured in the open position and periodically verified. During the times when two trains of Auxiliary Building DC Switchgear / Battery Charger are required, only two of three Room Coolers are required with one Room Cooler aligned to each train room. This 72 hour Completion Time allows sufficient time for maintenance activities to be completed without requiring unnecessary plant transients. In the event of a design basis accident during the 72 hour Completion Time, the opposite non-affected train Auxiliary Building DC Switchgear /

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BASES

APPLICABLE SAFETY ANALYSES (continued)

Battery Charger and Room Cooler are available to support the ESF equipment to mitigate the accident.

Load Control Center (LCC) Rooms (LCC D and E) Subsystem

FNP has one Room Cooler servicing each LCC room. Analysis has determined that each Room Cooler will provide adequate cooling to the given LCC room.

This 72 hour Completion Time allows sufficient time for maintenance activities to be completed without requiring unnecessary plant transients. In the event of a design basis accident during the 72 hour Completion Time, the opposite non-affected train LCC and Room Cooler are available to support the ESF equipment to mitigate the accident.

The ESF Room Coolers satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

ESF Room Coolers are required to be OPERABLE to ensure that the system functions to remove heat from the ESF equipment rooms during and after an accident assuming the worst case single failure occurs coincident with the loss of offsite power.

An ESF Room Cooler train is considered OPERABLE when the cooling coils, electrical fans, piping, manual valves, instrumentation, and cooling water supply required to perform the safety-related function is OPERABLE.

APPLICABILITY

The ESF Room Coolers must be OPERABLE to provide a safety-related cooling function consistent with the OPERABILITY requirements of the ESF equipment they support.

ACTIONS

The actions table is modified by a Note indicating that separate Condition entry is allowed for each ESF Room Cooler subsystem. This is acceptable since each ESF Room Cooler subsystem supports a separate ESF system. Having separate condition entry is consistent with the TS governing the associated ESF equipment, which allows concurrent inoperabilities of the separate ESF systems.

(continued)

BASES

ACTIONS (continued)

A.1

If one train of a required ESF Room Cooler subsystem is inoperable, action must be taken to restore the subsystem train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE ESF Room Cooler subsystem train is adequate to perform the heat removal function for its associated ESF equipment.

B.1 and B.2

If the ESF Room Cooler subsystem train cannot be restored to OPERABLE status within the associated Completion Time or two trains of the same ESF Room Cooler subsystem are inoperable, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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

SURVEILLANCE REQUIREMENTS

SR 3.7.19.1

Verifying the correct alignment for manual valves servicing safety-related equipment provides assurance that the proper flow paths exist for ESF Room Cooler 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.19.2

This SR verifies proper operation of the ESF Room Cooler fans on an actual or simulated actuation signal. Depending on the room cooler, this may be manual, high room temperature, an equipment running signal, or some combination. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Each Room Cooler Fan can be placed in Run mode locally. With the Room Cooler in the Run mode, all automatic functions are being met and the Room Cooler is considered OPERABLE.

REFERENCES

1. FSAR, Section 9.4.
2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources — Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate), and the onsite standby power sources (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 preferred offsite power sources and a single DG set. DG set A consists of the 1-2A and 1C DGs. DG set B consists of the 1B DG (Unit 1) and the 2B DG (Unit 2).

Offsite power is supplied to the 230 kV and 500 kV switchyard(s) from the transmission network by six transmission lines. From the 230 kV switchyard, two electrically and physically separated circuits provide AC power, through startup auxiliary transformers, to the 4.16 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 to the onsite Class 1E ESF bus(es).

In addition to providing a pre-determined sequence of loading the DGs, the train A and train B automatic load sequencers also function to actuate the required ESF loads on the offsite circuits. When offsite power is available, the automatic load sequencers function to simultaneously start the required ESF loads upon receipt of an SI actuation signal.

The onsite standby power source is provided from 4 DGs (1-2A, 1B, 2B, and 1C). The DGs are of two different sizes. The 1B, 2B, and

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BASES

BACKGROUND (continued)

1-2A DGs are rated at 4075 kW and the 1C DG is rated at 2850 kW. DG 1-2A and 1-C are assigned to the redundant load group train A. The train A load group is supplied from 4160V emergency Buses, F, H, and K. The 4160V H bus does not supply any design basis required loads by itself but is required to support the operation of DG 1C to supply the emergency Buses F and K which in turn supply design basis required loads. DGs 1B and 2B are assigned to the redundant load group train B. The train B load group is supplied from 4160V emergency Buses G, J, and L. The 4160V bus J does not supply any design basis required loads and is only required for the response to a station blackout which is not a design basis accident.

DGs 1B and 2B are dedicated to train B of Unit 1 and Unit 2, respectively, and each DG comprises a required DG set for its associated unit. DGs 1-2A and 1C are dedicated to train A but are shared between both units and together comprise a required DG set for both units. However, there are no design basis events in which DG 1-2A or 1C are required to supply power to the safety loads of both units simultaneously. In all events, DG 1-2A and 1C are assigned to only one of the two units depending on the event.

The 4.16 kV emergency busses required to supply equipment essential for safe shutdown of the plant at F, G, H, J, K, and L for each unit. These are supplied by two startup transformers on each unit connected to the offsite source during normal and emergency operating conditions. In the event one startup transformer on a unit fails, three of the emergency busses on that unit will be de-energized with their loss annunciated in the Main Control Room. The respective busses Diesel Generators will start and LOSP loads will be sequenced on to those busses. In the event Diesels fail, manual action will be required to re-energize the affected busses from the other startup transformer for that unit.

A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with 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, a sequencer strips nonpermanent loads from the ESF

(continued)

BASES

BACKGROUND (continued)

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 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 returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 2850 kW for DG 1C and 4075 kW for DGs 1-2A, 1B, and 2B. DG 1C has a 2000 hour rating of 3100 kW and overload permissible up to 3250 kW for 300 hours per year. DGs 1-2A, 1B, and 2B have a 2000 hour rating of 4353 kW and overload permissible up to 4474 kW for 2 hours in any 24 hour period with a maximum of 300 hours cumulative per year. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

Each diesel generator (DG) is connected to a shared fuel oil storage and transfer system. The shared fuel oil storage system consists of five underground storage tanks interconnected with piping, valves and redundant capacity fuel transfer pumps. This configuration allows for pumping diesel fuel oil from any DG fuel oil storage tank to any DG day tank or to any other DG fuel oil storage tank. The deliverable capacity of four tanks is sufficient to operate the required DGs for a period of 7 days while the DGs are supplying maximum single train, post loss of coolant accident load demands discussed in the FSAR. The diversity and defense in depth of the fuel oil transfer system ensures that even with one DG fuel oil transfer pump out of service on a single DG fuel oil storage tank, the capability still exists to maintain the DG Day Tank using multiple fuel transfer pumps. Therefore, one fuel transfer pump can be out of service on any given DG and the DG is still capable of meeting its design function.

BASES

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 or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits (i.e., consistent with the requirements of GDC 17) consisting of two physically independent transmission lines from the offsite transmission network to the switchyard and two independent circuits between the switchyard and the onsite Class 1E Electrical Power System along with separate and independent DG sets 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 (B1F, B2F, B1G, and B2G).

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.

(continued)

BASES

LCO (continued)

Two physically independent circuits between the transmission network and the onsite system may consist of any combination that includes two of the six transmission lines normally supplying the 230 and 500 kV switchyards and both independent circuits from the 230 kV switchyard to the Class 1E buses via Startup Auxiliary Transformers 1A (2A) and 1B (2B). The two of six combination of transmission lines may be shared between Unit 1 and 2. If either of the transmission lines are 500 kV, one 500/230 kV Autotransformer connecting the 500 and 230 kV switchyards is available. If both of the transmission lines are 500 kV, both 500/230 kV Autotransformers connecting the 500 and 230 kV switchyards are available. Any combination of 500 and 230 kV circuit breakers required to complete the independent circuits is permissible.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 12 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. For DG 1C this capability requires the support of the 4160 V H bus to enable DG 1C to supply the 4160 V buses F and K. 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 standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. All ESF buses, with two power sources available, have their supply breakers interlocked such that the buses can receive power from only one source at a time.

APPLICABILITY

The AC sources and sequencers 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

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 3.0.4b 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 3.0.4b, 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.

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power train. The redundant required features referred to in this Required Action include the motor driven auxiliary feedwater pump as well as the turbine driven auxiliary feedwater pump. One motor driven auxiliary feedwater pump does not provide 100% of the auxiliary feedwater flow assumed in the safety analyses. Therefore, in order to ensure the auxiliary feedwater safety function, the turbine

(continued)

BASES

ACTIONS

A.2 (continued)

driven auxiliary feedwater pump must be considered a redundant required feature addressed by this Required Action.

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) 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.

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

(continued)

BASES

ACTIONS

A.3 (continued)

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

The Condition B Required Actions are modified by a Note that is applicable when only one of the three individual DGs is inoperable. The note permits the use of the provisions of LCO 3.0.4c. The allowance provided by this note, to enter the MODE of applicability with a single inoperable DG, takes into account the capacity and capability of the remaining AC sources and the fact that operation is ultimately limited by the Condition B Completion Time for the inoperable DG set.

(continued)

BASES

ACTIONS

B.1 (continued)

To ensure a highly reliable power source remains with an inoperable DG set, 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 set is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. The redundant required features referred to in this Required Action include the motor driven auxiliary feedwater pump as well as the turbine driven auxiliary feedwater pump. One motor driven auxiliary feedwater pump does not provide 100% of the auxiliary feedwater flow assumed in the safety analyses. Therefore, in order to ensure the auxiliary feedwater safety function, the turbine driven auxiliary feedwater pump must be considered a redundant required feature addressed by this Required Action. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG set.

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 set exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one DG set inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG set inoperable coincident with one or more inoperable required support or supported features, or both, that

(continued)

BASES

ACTIONS

B.2 (continued)

are associated with the OPERABLE DG set, 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 set and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG set does not exist on the OPERABLE DG set, SR 3.8.1.6 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG set 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 set cannot be confirmed not to exist on the remaining DG set, performance of SR 3.8.1.6 suffices to provide assurance of continued OPERABILITY of that DG set.

In the event the inoperable DG set is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG set is not affected by the same problem as the inoperable DG set.

(continued)

BASES

ACTIONS (continued)

B.4

Operation may continue in Condition B for a period that should not exceed 10 days.

In Condition B, the remaining OPERABLE DG set and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 10 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. The redundant required features referred to in this Required Action include the motor driven auxiliary feedwater pump as well as the turbine driven auxiliary feedwater pump. One motor driven auxiliary feedwater pump does not provide 100% of the auxiliary feedwater flow assumed in the safety analyses. Therefore, in order to ensure the auxiliary feedwater safety function, the turbine driven auxiliary feedwater pump must be considered a redundant required feature addressed by this Required Action.

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.

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:

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems — Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

Operation may continue in Condition D for a period that should not exceed 24 hours.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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 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.

E.1

With all or part of Train A DG set and Train B DG set inoperable, the capacity of the remaining standby AC sources is reduced depending on which combination of individual DGs is affected. Thus, with an assumed loss of offsite electrical power, standby AC sources may be insufficient 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.

With all or part of each train of DG sets inoperable, operation may continue for a given unit for different periods of time depending on the combination of individual DGs that are inoperable. The length of time allowed increases with decreasing severity in the combinations of inoperable DGs. One set must be restored to operable status in 2 hours if DGs 1-2A, 1C, and 1B on Unit 1 or DGs 1-2A, 1C, and 2B on Unit 2 are inoperable. Operability of one set must be restored in 8 hours if DGs 1-2A and 1B on Unit 1 or DGs 1-2A and 2B on Unit 2 are inoperable. Operability of one set must be restored in 24 hours if DGs 1C and 1B on Unit 1 or DGs 1C and 2B on Unit 2 are inoperable.

(continued)

BASES

ACTIONS (continued)

F.1

Condition F provides the default Required Actions for the Conditions which address two inoperable offsite circuits or two inoperable DG sets. If the inoperable AC Sources cannot be restored to OPERABLE status within the applicable Completion Time, Required Action F.1 specifies that the unit be placed in MODE 3 within 6 hours. Once shut down, the unit is in a more stable condition and the time allowed to remain in MODE 3 is ultimately limited by the Required Actions and Completion Times applicable to a single inoperable AC Source based on the time that an AC Source initially became inoperable. In addition, the Required Actions applicable to one inoperable DG set or offsite circuit would remain applicable until both inoperable DG sets or offsite circuits are restored to OPERABLE status or the unit is placed in a MODE in which the LCO does not apply (MODE 5). The allowed Completion Times are reasonable to reach the required unit conditions from full power in an orderly manner and without challenging plant systems.

G.1

The sequencer(s) B1F, B2F, B1G, and B2G are an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the train. The 12 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.

H.1 and H.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 overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 13). In MODE 4 the Steam Generators and Residual Heat Removal System are available

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

to remove decay heat, which provides diversity and defense in depth. As stated in Reference 13, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action H.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

I.1

Condition I corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. This condition exists when any combination of sources from the categories in LCO 3.8.1 totaling three or more are not OPERABLE. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 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 SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.108 (Ref. 9), as addressed in the FSAR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3740 V is 90% of the nominal 4160 V output voltage. This value, which is specified in NEMA MG1 (Ref. 12), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V limits bus voltage to 110% of the nominal 4160 V. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.2 and SR 3.8.1.6

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.6 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.6 (continued)

In order to reduce stress and wear on diesel engines, some manufacturers recommend 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, which is only applicable when such modified start procedures are recommended by the manufacturer. The 1-2A, 1B, 1C and 2B DGs will automatically bypass the modified start sequence and proceed to normal voltage and frequency in response to an ESF or LOSP signal.

The DG shall be verified to accelerate to at least a synchronous speed of 900 rpm for the 2850 kW generator and 514 rpm for the 4075 kW generators.

SR 3.8.1.6 requires that the DG starts from standby conditions and achieves required voltage and frequency within 12 seconds. The permissive for closing the generator output breaker requires frequency to be greater than 57 Hz and voltage greater than 3952 V. The 12 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

The 12 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 12 second start requirement of SR 3.8.1.6 applies.

Since SR 3.8.1.6 requires a 12 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads in a range comparable to 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 per unit at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 3 is intended to be applied on a per unit basis and is not intended to preclude testing DGs on different units at the same time. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above a level which ensures sufficient time for manual transfer of fuel oil from the DG storage tank if the automatic transfer fails. The level is expressed as an equivalent volume in gallons, and ensures adequate fuel oil for a minimum of 3 hours of DG operation at the continuous rating.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.5

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 fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.6

See SR 3.8.1.2.

SR 3.8.1.7

Transfer of the unit 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

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, at 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 3.8.1.8

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 while maintaining a specified margin to the overspeed trip. The single load for each DG is approximately 1000 kW. This Surveillance may be accomplished by:

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 Regulatory Guide 1.9 (Ref. 3), 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

The voltage tolerance specified in this SR is derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence interval. The voltage specified is consistent with the design range of the equipment powered by the DG. SR 3.8.1.8.b is the steady state voltage value to which the system must recover following load rejection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.9

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG autostart time of 12 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODES 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, at 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 MODES 1, 2, 3 or 4. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.10

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power. Emergency loads are started simultaneously by logic in the load sequencers sensing the availability of offsite power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

The requirement to verify the connection 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, 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 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 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for the first Note is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for the second Note (which only applies to SR 3.8.1.10.d and e) is that during operation with the reactor critical, performance of SR 3.8.1.10.d and e could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

SR 3.8.1.11

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal and/or an ESF actuation test signal, i.e., are bypassed during accident conditions.

(continued)

BASES

SURVEILLLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.12

This surveillance 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 the 2000 hour load rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR. The steady-state generator voltage and frequency shall be maintained between 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note. The Note states that momentary transients due to changing bus loads do not invalidate this test.

SR 3.8.1.13

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 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is consistent with the 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 3.8.1.14

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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, at 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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.15

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.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.16

Under accident 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% (or 0.5 seconds, whichever is greater) 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

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 3.8.1.9, during a loss of offsite power actuation test signal in conjunction with an ESF 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. 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 MODES 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, at 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 MODES 1, 2, 3 or 4. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

This Surveillance demonstrates the DG capability to reject a load of 1200-2400 kW without overspeed tripping or exceeding the predetermined voltage limits. The DG 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 1200-2400 kW 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 DG output breaker(s) must remain closed such that the DG is connected to at least one ESF bus. All fuses and breakers on the energized ESF bus(es) must be verified not to trip.

This surveillance is modified by a note which states that testing of the shared Emergency Diesel Generator (EDG) set (EDG 1-2A or EDG 1C) on either unit may be used to satisfy this surveillance requirement for these EDGs for both units. The surveillance requirement consists of sufficient testing to demonstrate that each DG, the DG output breaker, and bus fuses and breakers can successfully withstand a 1200-2400 kW load rejection on each unit. This does not require, however, that each shared DG be aligned to each unit and a load rejection be performed in a redundant fashion. This surveillance is intended to assure the correct performance of the DG voltage regulators and governors.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.19

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This surveillance would also be applicable after any modifications which could affect DG interdependence.

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, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 1, 1971.
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. (Not used)
11. IEEE Standard 308-1971.
12. NEMA MG1-1967.
13. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources — Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources — Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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:

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.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems — Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG (1-2A, 1C, or 1(2)B), 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).

(continued)

BASES

LCO
(continued)

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(es). Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

A qualified offsite circuit between the transmission network and the onsite system may consist of any combination that includes one of the six transmission lines normally supplying the 230 and 500 kV switchyards and one qualified circuit from the 230 kV switchyard to the Class 1E buses via Startup Auxiliary Transformers 1A (2A) and 1B (2B). The one transmission line may be shared between Unit 1 and 2. If the transmission line is 500 kV, one 500/230 kV Autotransformer connecting the 500 and 230 kV switchyards is available. Any combination of 500 and 230 kV circuit breakers required to complete the qualified circuit is permissible.

The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 12 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 at ambient conditions.

Proper sequencer operation to sense loss of power or degraded voltage, initiate tripping of ESF bus offsite breakers and initiate DG start and DG output breaker closure and sequencing of shutdown loads are required functions for a DG to be considered OPERABLE.

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply both required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

(continued)

BASES

APPLICABILITY (continued)

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. Although two trains are required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of 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. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained.

(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)

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 any 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 SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.7 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.3 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.19 is excepted because starting independence is not required with the DG(s) that is not required to be operable. In addition, SR 3.8.1.9.C.2, SR 3.8.1.10, SR 3.8.1.15, SR 3.8.1.16, and SR 3.8.1.17 are not required to be met because the required operable DG is not required to respond to an SI signal or to have loads automatically sequenced on the associated ESF bus during MODES 5 and 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs 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. Therefore, if the surveillance were not performed within the required frequency (plus the extension allowed by SR 3.0.2) but the DG was required OPERABLE to meet LCO 3.8.2, it would not constitute a failure of the SR or failure to meet the LCO as described in Example 1.4-3 in Section 1.4 of these Technical Specifications. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is connected to a shared fuel oil storage and transfer system. The shared fuel oil storage system consists of 5 underground storage tanks interconnected with piping, valves and redundant capacity fuel transfer pumps. This configuration allows for pumping diesel fuel to the DG day tanks or from any storage tank to any other storage tank. The deliverable capacity of 4 tanks is sufficient to operate the required DGs for a period of 7 days while the DGs are supplying maximum post loss of coolant accident load demand discussed in the FSAR, Section 8.3.1.1.7 (Ref. 1). The maximum load demand is calculated using the assumption that a minimum of any two DGs are 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 a storage tank by either of two transfer pumps associated with each storage tank. The automatically controlled transfer pump, normally aligned to its DG day tank, is powered from a MCC supplied by the associated diesel, while the manually operated pump is powered from a MCC associated with another diesel. With the exception of transfer pumps for the tank associated with the station blackout diesel (2C), the pumps are powered from opposite trains. The opposite train power supplies ensure fuel in the associated storage tank can be transferred considering a design basis single failure. The transfer pumps for the station blackout diesel storage tank are supplied by train B power only. The automatic transfer pump can be fed from buses supplied by either DG 1B or 2B (in addition to DG 2C) and the manual transfer pump is fed from buses supplied by DG 2B. Therefore, the 2C fuel oil storage tank and associated transfer pumps may be available during design basis events to be used and credited as a manual supply to either B train design basis diesel (1B or 2B) when all applicable Technical Specification requirements are met. Operator actions are required to transfer fuel between storage tanks and day tank using the manually operated fuel transfer pumps.

(continued)

BASES

BACKGROUND (continued)

The usable fuel in a storage tank is the amount above the transfer pump suction nozzles that is available for transfer from a storage tank to a day tank. The amount of usable fuel is determined by correlating control room percent level indication to the applicable tank curve. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any day tank transfer pipe, valve or day 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. ASTM-D4057-06 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ASTM-D975-07 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, and specific gravity (or API gravity).

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. The onsite storage in addition to the engine oil sump is sufficient to ensure 7 days of continuous operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s). Each air start system consists of redundant air receivers. Each receiver has sufficient capacity to perform the required number of DG starts.

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 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Stored diesel fuel oil is required to have sufficient useable supply for 7 days operation of the required DGs supplying the required loads. 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 five successive DG start attempts without recharging the air start receivers. A single air receiver on each DG is sufficient to meet this operability requirement.
APPLICABILITY	The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

BASES

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for the required DG(s) 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.

B.1

With lube oil inventory < 238 gallons for a large DG or < 167 gallons for a small DG, 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 at least a 6 day supply (204 gallons for a large DG and 143 gallons for a small DG). 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 (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

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 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 both starting air receiver pressures on a DG < 350 psig for the 4075 kW DGs or < 200 psig for DG 1C, sufficient capacity for five successive DG start attempts does not exist. However, as long as at least one receiver pressure per DG is > 150 psig for the 4075 kW DGs or 90 psig for DG 1C, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air

(continued)

BASES

ACTIONS

E.1 (continued)

receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or one or more 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 useable fuel oil in the shared storage tanks (25,000 gallons each) to support the operation of the required DG(s) for 7 days at full load. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The inventory may consist of a combination of lube oil in storage and the useable sump volume above the manufacturer recommended minimum sump level or a total volume of lube oil in storage that is in addition to the lube oil normally maintained in each DG sump. The 238 gal requirement for the 4075 kW DGs and the 167 gal requirement for DG 1C are based on the DG manufacturer consumption values for 7 days of operation at full rated load. Implicit in this SR is the requirement to verify the capability

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

to transfer the lube oil from its storage location to the DG, when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-06 (Ref. 2)

b. Verify in accordance with the tests specified in ASTM D975-07 (Ref. 3) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 39° when tested in accordance with ASTM D1298-99 (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-04 (Ref. 7) or a water and sediment content within limits when tested in accordance with ASTM D2709-96 (Ref. 8)

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

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 D975-07 are met for new fuel oil when tested in accordance with ASTM D975-07, except that the analysis for sulfur may be performed in accordance with ASTM D1552-07 (Ref. 9), ASTM D2622-07 (Ref. 10), or ASTM D4294-03 (Ref. 11). 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 D6217-98 (Ref. 12). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each tank must be considered and tested separately.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that total particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. A single air receiver per DG has the capacity to meet the starting requirements. Therefore, only one receiver must be verified within the pressure limit per DG. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.4 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 8.3.1.1.7.
2. ASTM-D4057-06.
3. ASTM-D975-07.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. ASTM D1298-99.
7. ASTM D4176-04.
8. ASTM D2709-96.
9. ASTM D1552-07.
10. ASTM D2622-07.
11. ASTM D4294-03.
12. ASTM D6217-98.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources — Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC vital bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of two main systems. The Auxiliary Building System and the Service Water Intake Structure (SWIS) System. The Auxiliary Building 125 VDC system consists of two independent and redundant subsystems (Train A and Train B) which supply DC power to various ESF systems throughout the plant. Each Auxiliary Building subsystem (train) consists of a 125 VDC battery, an associated full capacity battery charger and all associated control equipment and interconnecting cabling. Each Auxiliary Building 125 VDC train is normally supplied by the associated battery charger (A or B). In the event of an A or B battery charger failure, battery charger C, the full capacity swing battery charger, may supply power to either train. Either train may be considered OPERABLE when supplied from battery charger C. Battery charger C input and output breakers are interlocked to prevent supplying power to a DC bus from the opposite train. Both the Auxiliary Building 125 VDC source subsystems (Train A and B) are required OPERABLE by this LCO.

The SWIS 125 VDC system provides a reliable source of power for controls, power loads, annunciation and alarms primarily for the safety-related Service Water System. The SWIS 125 VDC system consists of four battery/battery charger subsystems. Each subsystem consists of a 125 VDC battery and full capacity battery charger. The subsystems are divided into Train A and Train B which are shared between the two units. Each of the 4 subsystems can supply 100% of the required capacity for the associated train. Subsystems 1 and 2 are associated with Train A, with subsystem 1 being the normal

(continued)

BASES

BACKGROUND (continued)

supply, and subsystem 2 the standby supply. Subsystems 3 and 4 are associated with Train B, with subsystem 3 being the normal supply and subsystem 4 the standby supply. Each train has a manual transfer switch which is used to select which of the two available SWIS subsystems supplies that train. One SWIS subsystem is required OPERABLE for each train.

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 load group, 4.16 kV switchgear, and 600 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."

Each train of 125 VDC batteries is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

The Auxiliary Building batteries are stationary type consisting of 60 individual lead-calcium cells electrically connected in series to establish a nominal 125VDC power supply. Under both normal and accident conditions the batteries are capable of providing the required voltage for component operation considering an aging factor of 25% and minimum electrolyte temperature of 60°F. The battery float voltage is 2.20V per cell average and 132V total terminal voltage. During an LOSP or LOSP with SI, the Auxiliary Building batteries supply safety-related loads for a period of less than one minute duration without charger support. The design is such that subsequent to LOSP, the battery chargers are re-energized by the Diesel Generators within one minute.

(continued)

BASES

BACKGROUND (continued)

Although not a requirement for the mitigation of design basis events, each battery is capable of providing LOSP or LOSP plus SI loads for a period of 2 hours assuming the single failure loss of the battery charger aligned at the onset of the event. During such an occurrence, the redundant train battery with its connected charger remains fully capable of providing DC power to redundant train safety-related loads. The batteries also have the capacity to supply normal operating loads for a period of 2 hours without charger support as discussed in the FSAR Chapter 8.3 (Ref. 4). The 2 hour period of time is adequate to allow alignment of the spare battery charger to the affected battery without disrupting continued operation.

The SWIS batteries are stationary type consisting of individual lead-calcium cells electrically connected in series to establish a nominal 125 VDC power supply. They are sized to furnish the anticipated vital loads without dropping below a total battery voltage of 105 V. Under both normal and accident conditions the batteries are capable of providing the required voltage for component operation considering an aging factor of 25% and a minimum electrolyte temperature of 35°F. The battery float voltage is 2.20 V per cell average and 132 V total. Each SWIS battery subsystem has adequate capacity to carry its loads without charger support for a period of at least 2 hours as discussed in the FSAR, Chapter 8.3 (Ref. 4).

Each Train A and Train B DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has adequate capacity to restore its battery to full charge after the battery has been discharged while carrying steady-state normal or emergency loads. The time required to recharge the battery to full charge is compatible with the recommendation of the battery manufacturer (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 6), and in the FSAR, Chapter 15 (Ref. 7), 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(c)(2)(ii).

LCO

Both the Auxiliary Building 125 VDC source subsystems (Train A and B) and two SWIS 125 VDC source subsystems (one in each train) including a battery charger for each Auxiliary Building and SWIS battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

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."

BASES

ACTIONS

A.1

Condition A represents one train of Auxiliary Building DC electrical power with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

[For Unit 1 only for cycle 19] The second Completion time for Condition A represents the 1B train of Auxiliary Building DC electrical power subsystem due to an inoperable battery. With the 1B Auxiliary Building battery inoperable, the DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in the loss of 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 breakers, etc.) rely upon the battery. The 12 hour limit allows sufficient time to effect restoration of the 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 2.02 volts, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure would, however, result in the complete loss of the remaining 125 VDC electrical power subsystems with attendant loss of ESF functions, in the case of the Auxiliary Building DC power subsystem, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the Auxiliary Building DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

(continued)

BASES

ACTIONS (continued)

B.1 and D.1

Conditions B and D represent one Auxiliary Building or SWIS DC electrical power subsystem with connection resistance not within the specified limit. Consistent with the guidance in IEEE-450, connection resistance not within the limit is an indication that the affected battery requires attention to restore the resistance to within the limit but is not a basis on which to declare the battery inoperable. Therefore, the 24 hour Completion Time allowed to restore the battery connection resistance to within the required limit is a reasonable time considering that variations in connection resistance do not mean the battery is incapable of performing its required safety function, but is an indication that the battery requires maintenance.

C.1 and C.2

If the inoperable Auxiliary Building DC electrical power subsystem cannot be restored to OPERABLE status or the connection resistance restored to within the limit within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 11). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 11, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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

If a required SWIS DC electrical power subsystem is inoperable or the connection resistance is not restored to within the limit and the associated Completion Time has expired, the Service Water System train supported by the affected SWIS DC electrical power subsystem must be declared inoperable. The capability of the affected SWIS DC electrical power subsystem to fully support the associated train of Service Water is not assured. Therefore, consistent with the definition of OPERABILITY, the associated train of Service Water must be declared inoperable immediately, thereby limiting operation in this condition to the Completion Time associated with the affected Service Water System train.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is applying a voltage to the battery to maintain it in a fully charged condition during normal operation. The float voltage of 2.2 V per cell or 132 V overall is higher than the nominal design voltage of 125 V and is consistent with the manufacturer's recommendations for maintaining a full charge. Verifying that terminal voltage is ≥ 127.8 V provides assurance that the average of all cell voltages is maintained greater than 2.13 V. Maintaining float voltage at the higher value of 2.2 V per cell prolongs cell life expectancy. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2

Visual inspection to detect excessive corrosion on the battery terminals or connectors, or measurement of the post to post resistance of these items provides an indication of the need for cleaning and/or retorqueing.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and post to post resistance measurements of battery terminals or connectors provide an indication of the need for cleaning and/or retorqueing. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.4.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.6

This SR requires that each required battery charger be capable of supplying 536 amps (Auxiliary Building chargers) and 3 amps (SWIS chargers) at 125 V for ≥ 4 hours. These requirements are based on

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.

This surveillance is modified by a Note which clarifies that it may be performed in any mode of operation provided certain conditions are met. The design is such that any battery charger may be tested while a spare or redundant battery and/or charger is in service in its place.

The spare or redundant battery and/or charger must be within the 18 month surveillance frequency to maintain the DC subsystem(s) to which they are aligned OPERABLE. This operational flexibility maintains TS OPERABILITY of the applicable battery and DC train while testing the normally aligned charger.

SR 3.8.4.7

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (design load profile) of the DC electrical power system. The discharge rate and test length should correspond to the design load profile requirements as specified in Reference 4.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by three Notes. Note 1 allows the performance of a performance discharge test in lieu of a service test once per 60 months. Note 2 allows the performance of a modified performance discharge test in lieu of a service test at any time.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The modified performance discharge test is a simulated duty cycle consisting of just two rates: the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelop the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 3 is that performing the Surveillance for the Auxiliary Building batteries would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODES 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODES 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8. The modified performance discharge test may be used to satisfy SR 3.8.4.8 while simultaneously satisfying the requirements of SR 3.8.4.7 at any time. The performance discharge test may be used to satisfy 3.8.4.8 while simultaneously satisfying the requirements of SR 3.8.4.7 once per 60 months.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 9). This reference recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the battery shows degradation, or if the battery has reached 85% of its expected life or 17 years, whichever comes first, the Surveillance Frequency is reduced to 18 months. Degradation is indicated, according to IEEE-450 (Ref. 9), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is > 10% below the manufacturer's rating.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance for the Auxiliary Building batteries would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODES 1, 2, 3, or 4 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial surveillance, and a perturbation

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

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 MODES 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1971.
4. FSAR, Section 8.3.
5. None.
6. FSAR, Chapter 6.
7. FSAR, Chapter 15.
8. Regulatory Guide 1.93, December 1974.
9. IEEE-450-1980.
10. Regulatory Guide 1.32, February 1972.
11. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power sources required to support the necessary portions of AC, DC, and AC vital bus electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems — Shutdown," shall be OPERABLE. At a minimum, at least one train

(continued)

BASES

LCO (continued)

of DC electrical power source from the Auxiliary Building (Train A or B) and Service Water Intake Structure (Train A or B) consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling within the train, is required operable.

In the case where the requirements of LCO 3.8.10 call for portions of a second train of the distribution subsystems to be OPERABLE (e.g., to support two trains of RHR, two trains of CREFS, or instrumentation such as source range indication, containment purge and exhaust isolation actuation, or CREFS actuation), the required DC buses associated with the second train of distribution systems are OPERABLE if energized to the proper voltage from either:

- An OPERABLE DC Source consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling associated with that train, or

- A battery charger using the corresponding control equipment and interconnecting cabling within the train.

The above requirements ensure the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents.)

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features needed to mitigate a fuel handling accident are available;

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. 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.

BASES

ACTIONS

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

If two subsystems are required by LCO 3.8.10, the remaining subsystem with DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. 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). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

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 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 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

BASES

REFERENCES	1.	FSAR, Chapter 6.
	2.	FSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources — Operating," and LCO 3.8.5, "DC Sources — Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), 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.

Battery cell parameters satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

BASES

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, the battery electrolyte limits of this LCO are only required to be met 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 required batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1 in the accompanying LCO, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met and operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 2 hours (Required Action A.1). This check will provide a quick indication of the status of the remainder of the battery cells. Two hours provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. Two hours is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

(continued)

BASES

ACTIONS

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable prior to declaring the battery inoperable.

B.1

With one or more required batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below the minimum temperature limit, or the average cell float voltage ≤ 2.13 volts, which is equivalent to overall battery terminal voltage ≤ 127.8 volts, are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with the values specified in Table 3.8.6-1. IEEE-450 (Ref. 3) recommends regular battery inspections including voltage, specific gravity, and electrolyte temperature of pilot cells. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.2

The inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In addition, within 7 days of a battery discharge < 110 V or a battery overcharge > 150 V, the battery must be demonstrated to meet

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.2 (continued)

Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance verification that the average temperature of 10 connected representative cells is ≥ 60°F for the Auxiliary Building batteries and ≥ 35°F for the SWIS batteries, is consistent with a recommendation of IEEE-450 (Ref. 3), that states that the temperature of electrolytes in representative cells should be determined. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on design considerations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those with the lowest specific gravity and voltage from the previous quarterly surveillance.

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.08 V per cell. This value is based on operating experience. This experience has shown numerous instances when at least one cell was measured at less than 2.13 volts DC at FNP. In such instances, the minimum average specific gravity was 1.197 equating to approximately 90% capacity which is well above that required by the design load profile. In addition, the float voltage limit of 2.08V is acceptable based on: 1) float voltage by itself not being a comprehensive indicator of the state of charge of a battery; 2) pilot cells exhibiting ≤ 2.13V not eliminating battery capability to perform design function; and 3) IEEE 450-1980 Appendix C1 does not consider a cell potentially degraded unless its voltage on float charge is ≤ 2.07V.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195. The manufacturers recommended fully charged specific gravity is 1.215 for the Auxiliary Building and 1.210 for the SWIS batteries. The value of 0.015 below the manufacturers recommended fully charged value for SWIS batteries has been adopted as the Category A minimum for both the Auxiliary Building and SWIS batteries. This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.190 with the average for all connected cells ≥ 1.195. The manufacturers recommended fully charged specific gravity is 1.215 for the Auxiliary Building and 1.210 for the SWIS batteries. The value of 0.020 below the manufacturers recommended fully charged value for SWIS batteries has been adopted as the Category B minimum for each connected cell for both the Auxiliary Building and SWIS batteries. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limits for float voltage are based on operating experience, which has shown that a cell voltage of 2.02 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.190 is based on operating experience. In addition to that limit, if a cell is < 1.190, then it shall not have decreased more than 0.080 from the previous test.

The footnotes to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. IEEE-450-1980.

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.

There are four Class 1E inverters that supply the four vital AC distribution panels. Each inverter is connected independently to one distribution panel. The power for the inverters is from the Class 1E 125 VDC Train A and B Auxiliary Building station batteries or their associated chargers when the batteries are on float. The four Class 1E inverters provide the preferred source of 120 V, 60 Hz power for the reactor protection system, the engineered safety feature actuation system, the nuclear steam supply system control and instrumentation, the post accident monitoring system, and the safety related radiation monitoring system.

Each distribution panel can be connected to an alternate source of Class 1E 120 VAC power. The backup power source is an emergency 600 V MCC supplying a 120 V regulated panel through a constant voltage transformer (CVT). Should the normal distribution panel source fail, the inverter static transfer switch will function to supply the vital AC distribution panels from this alternate source.

Specific details on inverters and their operating characteristics are found in 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(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.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters (two per train) ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized.

Operable inverters require the associated vital bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 VDC station battery.

This LCO is modified by a Note that allows two inverters to be disconnected from a common battery for ≤ 24 hours, if the vital bus(es) are powered from a Class 1E alternate power source consisting of the inverters static transfer switch and the associated CVT during the period and all other inverters are OPERABLE. This allows an equalizing charge to be placed on the associated 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.

(continued)

BASES

LCO (continued)

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."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is re-energized from its Class 1E CVT.

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 8 hours. The associated static transfer switch normally provides a bumpless transfer of power to the alternate AC source (Class 1E CVT).

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

(continued)

BASES

ACTIONS

A.1 (continued)

is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). 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 overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

BASES

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 and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 8.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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 Protection 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.

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Per LCO 3.8.10, "Distribution Systems — Shutdown," the necessary portions of the necessary AC vital bus electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE. At a minimum, at least one train of AC vital bus electrical power subsystems energized from the associated inverters connected to the respective DC bus is required to be OPERABLE.

In the case where the requirements of LCO 3.8.10 call for portions of a second train of the distribution subsystems to be OPERABLE (e.g., to support two trains of RHR, two trains of CREFS, or instrumentation such as source range indication, containment purge and exhaust isolation actuation, or CREFS actuation), the required portions of the second train of AC vital bus electrical power distribution subsystems may be energized from the associated inverter(s) connected to the respective DC bus, or the alternate Class 1E power source consisting of the inverter static transfer switch and the associated constant voltage transformer. Class 1E power and distribution systems are normally used because these systems are available and reliable. However, due to events such as maintenance or modification, portions of the Class 1E system may be temporarily unavailable. In such an instance the plant staff assesses the alternate systems to ensure that defense in depth is maintained and that risk is minimized.

This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems needed to mitigate a fuel handling accident are available;

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

(continued)

BASES

APPLICABILITY (continued)

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

If two trains are required by LCO 3.8.10, "Distribution Systems — Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. 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). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required 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 and frequency

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1 (continued)

output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 into two redundant and independent AC, DC, and AC vital bus electrical power distribution trains.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 4.16 kV bus and secondary 600 and 208/120 V buses, distribution panels, motor control centers and load centers. Each train of 4.16 kV ESF buses has at least one separate and independent offsite source of power as well as an onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a preferred offsite source. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16 kV ESF bus(es). Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources — Operating," and the Bases for LCO 3.8.4, "DC Sources — Operating."

The secondary AC electrical power distribution system for each train includes the safety related load centers, motor control centers, and distribution panels shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E constant voltage source transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters — Operating." Each constant voltage source transformer is powered from a Class 1E AC bus.

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,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

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, load centers, motor control centers, and distribution panels 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

(continued)

BASES

LCO (continued)

battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage or Class 1E constant voltage transformer.

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of 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.

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 and A.2

With the shared Load Center (LC) 1-2R unable to be supplied power from either its Unit 1 or Unit 2 power supply (i.e., the 1H or 2H 4160V bus, respectively), the 1C DG will be unavailable to energize the affected unit (i.e., the unit unable to supply power to the LC 1-2R). The 1C DG will, however, remain available to energize the non-affected unit following a design basis accident. Aligning the 1C DG unit selector switch to the non-affected unit will ensure the LC 1-2R will

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

remain energized via the Unit 1 or Unit 2 4160V H bus to which the 1C DG is aligned during a design basis accident. This will also ensure the 1C DG is unavailable to energize the affected unit. Therefore, consistent with the definition of OPERABILITY, the 1C DG must be declared inoperable for the affected unit.

B.1

If the Required Action and associated Completion Time of Condition A cannot be met, the power supply to the Unit 1 Service Water (SW) System automatic turbine building isolation valves (MOVs 515 and 517) will be unavailable following a design basis accident, so these valves must also be declared inoperable. Required Action A.2 will still apply, so the 1C DG must also be declared inoperable.

C.1 and C.2

With the shared Load Center 1-2R inoperable for reasons other than Condition A or Condition B, the Unit 1 Service Water (SW) System automatic turbine building isolation valves (MOVs 515 and 517) and the 1C DG must be declared inoperable immediately. The load center provides power to Unit 1 MOVs 515 and 517 and the 1C DG auxiliary systems. Therefore, consistent with the definition of OPERABILITY, these loads must be declared inoperable immediately.

D.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except AC vital buses, inoperable for reasons other than Condition A, B, or C, and a loss of safety function has not yet occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety function necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

(continued)

BASES

ACTIONS

D.1 (continued)

Condition D 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.

E.1

With one or more AC vital buses inoperable, and a loss of safety function has not yet occurred, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 8 hours by powering the bus from the associated inverter via inverted DC or Class 1E constant voltage transformer.

Condition E represents one or more AC vital buses without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected vital bus.

(continued)

BASES

ACTIONS

E.1 (continued)

This 8 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 8 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 8 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

F.1

With Auxiliary Building DC bus(es) in one train inoperable, the remaining Auxiliary Building 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 subsystem 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 F represents one train without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is,

(continued)

BASES

ACTIONS

F.1 (continued)

therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that 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).

G.1 and G.2

If the inoperable distribution subsystem(s) addressed by Conditions D, E, or F cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain

BASES

ACTIONS

G.1 and G.2 (continued)

in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action G.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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

With one SWIS DC electrical power distribution subsystem inoperable, the Service Water System train supported by the affected SWIS DC electrical power distribution subsystem must be declared inoperable. The capability of the affected SWIS DC electrical power distribution subsystem to fully support the associated train of Service Water is not assured. Therefore, consistent with the definition of OPERABILITY, the associated train of Service Water must be declared inoperable immediately, thereby limiting operation in this condition to the Completion Time associated with the affected Service Water System train.

I.1

With two trains with 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.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.8.9.1</u> 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Chapter 6. 2. FSAR, Chapter 15. 3. Regulatory Guide 1.93, December 1974. 4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

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	4160 V SWGR	1/2 F and 1/2 K	1/2 G and 1/2 L
	600 V LC	1/2 D, K**, and R**	1/2 E and 1/2 L**
DC Buses	125 V SWGR	1/2 A	1/2 B
	125 V Dist. Panels	1/2 M	1/2 N
Vital AC Buses	120	1/2 A and 1/2 B	1/2 C and 1/2 D

* Each train of the AC and DC electrical power distribution systems is a subsystem.

** Indicates buses shared between Units 1 and 2.

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, and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components — all specifically addressed in each LCO.

The necessary portions of the AC electrical power distribution subsystems are considered OPERABLE if they are energized to their proper voltages.

The necessary portions of the DC electrical power subsystems are considered OPERABLE if the following criteria are satisfied:

- At least one train of the necessary portions of DC electrical subsystems is energized to the proper voltage by an OPERABLE train of DC sources consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling associated with that train; and

- In the case where portions of a second train of the DC electrical subsystems are required OPERABLE (to support two trains of RHR, two trains of CREFS, or instrumentation such as source range indication, containment purge and exhaust isolation actuation, or CREFS actuation), the required portions of the second train of DC electrical subsystems are OPERABLE when energized to the proper voltage from either:

    - an OPERABLE train of DC sources consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling associated with that train, or

    - a battery charger using the corresponding control equipment and interconnecting cabling within the train.

(continued)

BASES

LCO (continued)

The necessary portions of the AC vital bus subsystems are considered OPERABLE if the following criteria are satisfied:

- At least one train of the necessary portions of AC vital bus electrical power subsystems is energized to the proper voltage by OPERABLE inverters connected to the respective DC bus; or

- In the case where portions of a second train of AC vital bus subsystems are required OPERABLE (to support two trains of RHR, two trains of CREFS, or instrumentation such as source range indication, containment purge and exhaust isolation actuation, or CREFS actuation), the required portions of the second train of AC vital bus electrical power distribution subsystems are OPERABLE when energized to the proper voltage from either:

    - OPERABLE inverter(s) connected to the respective DC bus, or

    - the alternate Class 1E power source consisting of the inverter static transfer switch and the associated constant voltage transformer.

Class 1E power and distribution systems are normally used because these systems are available and reliable. However due to events such as maintenance or modification, portions of the Class 1E system may be temporarily unavailable. In such an instance the plant staff assesses the alternate systems to ensure that defense in depth is maintained and that risk is minimized.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

(continued)

BASES

APPLICABILITY (continued)

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

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

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

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

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 control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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 the filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity 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 having direct access to the reactor core. The refueling boron concentration limit specified in the COLR ensures that an overall core reactivity of $k_{eff} \leq 0.95$ is maintained during fuel handling, with control rods and fuel assemblies in the most adverse configuration (least negative reactivity) consistent with the assumptions of the applicable safety analysis.

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 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

(continued)

BASES

BACKGROUND (continued)	refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.5, "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.

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% Δk/k margin to criticality 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 boron dilution event analyzed for refueling MODE requires that manual action be taken to mitigate the dilution event and prevent a loss of SHUTDOWN MARGIN. The audible count rate from the source range neutron flux monitors required OPERABLE in LCO 3.9.2 provides prompt and definite indication of any boron dilution. The count rate increase is proportional to the subcritical multiplication factor and allows operations to recognize the initiation of a boron dilution event in time to isolate the primary water makeup source before SHUTDOWN MARGIN is lost (Ref. 2).

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the filled portions of the RCS, the refueling canal, and the refueling cavity that have direct access to the core while in MODE 6. The

(continued)

BASES

LCO (continued)

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 $k_{eff} \leq 0.95$. In other MODES, the LCOs for Rod Group Alignment Limits, Shutdown Bank Insertion Limits, Control Bank Insertion Limits, and SHUTDOWN MARGIN 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. The Note states that the limits on boron concentration are only applicable to the refueling canal and the refueling cavity when those volumes are connected to the Reactor Coolant System. When the refueling canal and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the filled portions of the RCS, the refueling canal, or the refueling cavity that has direct access to the core 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 or normal cooling of the coolant volume for the purpose of maintaining system temperature.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

BASES

ACTIONS

A.3 (continued)

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 connected portions of the refueling canal and the refueling cavity, that have direct access to the core is within the COLR limits. The boron concentration of the coolant in each required volume that has direct access to the core is determined periodically by chemical analysis. Prior to re-connecting portions of the refueling canal or the refueling cavity to the RCS, this SR must be met per SR 3.0.4. If any dilution has occurred while the cavity or canal were disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

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

2. FSAR, Chapter 15.2.4.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. Temporary neutron flux detectors which provide equivalent indication may be utilized in place of installed instrumentation.

Two installed Westinghouse source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux with a 5% instrument accuracy. The detectors also provide continuous visual indication in the control room and an audible count rate to alert operators to a possible dilution accident. The operator may select either installed Westinghouse source range neutron flux monitor as the signal source for the audio indication. The NIS is designed consistent with the intent of the criteria presented in Reference 1.

The installed source range Gamma-Metrics post accident neutron flux monitor is an enriched U-235 fission chamber operating in the ion chamber region of the gas filled detector characteristic curve. The detector monitors the neutron flux in counts per second. The instrument range covers six decades of neutron flux with a 2% instrument accuracy. The detector also provides continuous visual indication in the control room.

Three installed source range neutron flux monitors are available, only two are required to be operable. Two of the three installed source range neutron flux monitors OPERABLE will satisfy L.C.O. 3.9.2 as long as one channel of audible count rate is OPERABLE and continuous visual indication in the control room is available from at least two monitors.

BASES

APPLICABLE SAFETY ANALYSES	Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity. The audible count rate from the source range neutron flux monitors provides prompt and definite indication of any boron dilution. The count rate increase is proportional to the subcritical multiplication factor and allows operators to promptly recognize the initiation of a boron dilution event. Prompt recognition of the initiation of a boron dilution event is consistent with the assumptions of the safety analysis and is necessary to assure sufficient time is available for isolation of the primary water makeup source before SHUTDOWN MARGIN is lost (Ref. 2). The High-Flux at Shutdown Alarm, because of the delay for the neutron flux to reach the alarm setpoint, does not provide prompt indication of the initiation of a boron dilution event and the delay introduced by the alarm setpoint is not consistent with the assumptions of the safety analysis. The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(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 channel of source range instrumentation must provide visual indication in the control room. In addition, one channel of audible count rate must be available to alert the operators to the initiation of a boron dilution event. The preferred location of the required audible count rate is in the control room. In the case where the required audible count rate is only available in containment, it is acceptable to station a licensed operator in containment to communicate with the control room and alert the operators to a possible dilution accident. In the event that the required channel of audible count rate is lost, all unborated water sources must be isolated. The isolation of unborated water sources precludes a boron dilution accident. Once actions are initiated to isolate the unborated water sources, they must be continued until all the necessary flow paths are isolated. Movement of fuel may continue provided two channels of source range visual indication are available in the control room.

BASES

APPLICABILITY

In MODE 6, two 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 OPERABILITY requirements for the Westinghouse installed source range detectors and circuitry are addressed by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

The source range neutron flux monitors have no control function in MODE 6 and are assured to alarm (visual indication and audio) only during an FSAR design basis accident or transient. The source range neutron flux monitors provide the only on-scale monitoring of the neutron flux during refueling. Therefore, they are being retained in the Technical Specifications.

In MODES 1-3, the operability requirements for the installed source range Gamma-Metrics post accident neutron flux monitor are addressed by LCO 3.3.4, "Remote Shutdown System."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE (providing visual indication in the control room), redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position or normal cooling of the coolant volume for the purpose of maintaining system temperature.

B.1

With no required source range neutron flux monitor OPERABLE (providing visual indication in the control room), 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.

(continued)

BASES

ACTIONS (continued)

B.2

With no required source range neutron flux monitor OPERABLE (providing visual indication in the control room), there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of 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 Completion Time is reasonable, considering the low probability of a change in core reactivity during this time period.

C.1

With no audible count rate available, prompt and definite indication of a boron dilution event, consistent with the assumptions of the safety analysis, is lost. In this situation, the boron dilution event may not be detected quickly enough to assure sufficient time is available for operations to manually isolate the unborated water sources and stop the dilution prior to the loss of SHUTDOWN MARGIN. Therefore, action must be taken to prevent an inadvertent boron dilution event from occurring. This is accomplished by isolating all the unborated water flow paths to the reactor coolant system from the Reactor Makeup Water System and the Demineralized Water System. Isolating these flow paths ensures that an inadvertent dilution of the reactor coolant boron concentration is prevented. The Completion Time of "immediately" assures a prompt response by operations and requires an operator to initiate actions to isolate an affected flow path immediately. Once actions are initiated, they must be continued until all the necessary flow paths are isolated. Movement of fuel may continue provided two channels of visual indication are available in the control room.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves and evaluating those curves. The CHANNEL CALIBRATION for the Westinghouse monitors also includes verification of the audible count rate function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.

2. FSAR, Section 15.2.4.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.3 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 limited to maintain dose consequences within regulatory limits 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 "refueling integrity" rather than "containment OPERABILITY." Refueling integrity means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the 10 CFR 50, 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 50.67. 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

(continued)

BASES

BACKGROUND (continued)

when refueling integrity 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, refueling integrity is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain capable of being closed.

The requirements for refueling integrity ensure that a release of fission product radioactivity within containment will be limited to maintain dose consequences within regulatory limits.

The Containment Purge and Exhaust System includes two subsystems. The normal subsystem includes a 48-inch purge penetration and a 48-inch exhaust penetration. The second subsystem, a minipurge system, includes an 8-inch purge and an 8 inch exhaust line that utilize the 48-inch penetrations. During MODES 1, 2, 3, and 4, the two 48-inch purge valves in each of the normal purge and exhaust penetrations are secured in the closed position. The two 8-inch minipurge valves in each of the two minipurge lines may be opened in these MODES in accordance with LCO 3.6.3, "Containment Isolation Valves," but are closed automatically by the Engineered Safety Features Actuation System (ESFAS) instrumentation specified in LCO 3.3.6, "Containment Purge and Exhaust Isolation Instrumentation." Neither of the subsystems is subject to a Specification in MODE 5.

In MODE 6, large air exchanges are necessary to conduct refueling operations. The normal 48-inch purge system is used for this purpose, and all four valves are closed by the ESFAS instrumentation specified in LCO 3.3.6, "Containment Purge and Exhaust Isolation Instrumentation."

The minipurge system is not normally used in MODE 6. However, if the minipurge valves are opened they are capable of being closed automatically by the instrumentation specified in LCO 3.3.6, "Containment Purge and Exhaust 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

(continued)

BASES

BACKGROUND (continued)	isolation valve, a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods allowed under the provisions of 10 CFR 50.59 may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment (Ref. 1).
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. 2). The fuel handling accident analyzed includes dropping a single irradiated fuel assembly. The requirements of LCO 3.9.6, "Refueling Cavity Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are less than the dose limits specified in 10 CFR 50.67, and the more restrictive offsite exposure criteria of Standard Review Plan, Section 15.0.1 (Ref. 3). Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(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 purge and exhaust penetrations, the equipment hatch and the personnel air locks. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge and Exhaust Isolation System. For the equipment hatch and personnel air locks, closure capability is provided by a designated trained closure crew and the necessary equipment. The OPERABILITY requirements for LCO 3.3.6, "Containment Purge and Exhaust Isolation Instrumentation," ensure that the automatic purge and exhaust valve closure times specified in the FSAR can be achieved and, therefore, meet the assumptions used in the safety achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves

(continued)

BASES

LCO (continued)

are terminated, such that radiological doses are within the acceptance limit.

The equipment hatch and personnel air locks are considered isolable when the following criteria are satisfied:

1. the necessary equipment required to close the hatch and personnel air locks is available,

2. at least 23 feet of water is maintained over the top of the reactor vessel flange in accordance with Specification 3.9.6,

3. a designated trained closure crew is available.

The equipment hatch and personnel air locks door openings must be capable of being cleared of any obstruction so that closure can be achieved as soon as possible.

The containment personnel air lock and emergency personnel air lock doors may be open during movement of irradiated fuel in the containment and during CORE ALTERATIONS provided that one door in each air lock is capable of being closed in the event of a fuel handling accident. Should a fuel handling accident occur inside containment, one door in each personnel air lock will be closed following an evacuation of containment.

The closure of the equipment hatch and the personnel air locks will be completed promptly following a fuel handling accident within containment.

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 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and 2) special individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

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

(continued)

BASES

APPLICABILITY (continued)

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 Purge and Exhaust Isolation System not capable of automatic actuation when the purge and exhaust 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.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

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 purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also, the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal from each of the containment purge radiation monitoring instrumentation channels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the components being tested by this SR will require reevaluation of STI Evaluation Number 558904 in accordance with the Surveillance Frequency Control

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.2 (continued)

Program. SR 3.6.3.4 demonstrates that the isolation time of each valve is in accordance with the INSERVICE TESTING PROGRAM requirements. These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment. This SR is modified by a Note stating that this Surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability.

SR 3.9.3.3

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 Frequency is controlled under the Surveillance Frequency Control Program.

The SR 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.

REFERENCES

1. GPU Nuclear Safety Evaluation SE-0002000-001, Rev. 0, May 20, 1988.
2. FSAR, Section 15.4.5.
3. NUREG-0800, Section 15.0.1, Rev. 0, July 2000.
4. Regulatory Guide 1.195, “Methods and Assumptions for Evaluating Radiological Consequences of Design Basis Accidents at Light-Water Nuclear Power Reactors,” May 2003.

B 3.9 REFUELING OPERATIONS

B 3.9.4 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 a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be OPERABLE and in operation 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 and Coolant Circulation — High Water Level specification satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

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

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. Management of gas voids is important to RHR System OPERABILITY.

The LCO is modified by a Note that allows the required operating RHR loop to not be in operation for up to 1 hour per 8 hour period, provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction 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.

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 3.9.6, "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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

BASES

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. Reduced boron concentrations can occur by the addition of water with a lower boron concentration than the required boron concentration specified in the COLR. Therefore, actions that could result in the addition of water to the RCS with a boron concentration less than the required boron concentration specified in the COLR must be suspended immediately.

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.

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 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4, A.5, A.6.1, and A.6.2

If no RHR is in operation, the following actions must be taken:

a) the equipment hatch must be closed and secured with four bolts;
b) one door in each air lock must be closed; and
c) each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

(continued)

BASES

ACTIONS

A.4, A.5, A.6.1, and A.6.2 (continued)

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.4.2

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.2 (continued)

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.2 (continued)

accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. FSAR, Section 5.5.7.

B 3.9 REFUELING OPERATIONS

B 3.9.5 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 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 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 a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant 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 and Coolant Circulation — Low Water Level specification satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, 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.

(continued)

BASES

LCO (continued)

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. Management of gas voids is important to RHR System OPERABILITY.

The LCO requirements are modified by two Notes. The first note provides an exception to the requirements for one RHR loop to be OPERABLE and one RHR loop to be in operation. This exception is necessary to ensure the RHR System may be realigned as necessary for up to 2 hours to perform the required surveillance testing necessary to verify the RHR System performance in the ECCS injection mode of operation.

The second Note permits the RHR pumps to be de-energized for ≤ 15 minutes when switching from one train to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is limited to > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

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 3.9.4, "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 3.9.4, 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.

(continued)

BASES

ACTIONS (continued)

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur by the addition of water with a lower boron concentration than the required boron concentration specified in the COLR. Therefore, actions that could result in the addition of water to the RCS with a boron concentration less than the required boron concentration specified in the COLR must be suspended immediately.

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, B.4, B.5.1, and B.5.2

If no RHR is in operation, the following actions must be taken:

a) the equipment hatch must be closed and secured with four bolts;
b) one door in each air lock must be closed; and
c) each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.2

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensable gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.3 (continued)

susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.5.3 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.
REFERENCES	1. FSAR, Section 5.5.7.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies or performance of CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, 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, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to less than 10 CFR 50.67 limits (Ref. 4), as well as the more restrictive guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.183 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for iodine.

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 3 and 4).

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

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.
APPLICABILITY	LCO 3.9.6 is applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, and when moving irradiated fuel assemblies within containment. Unlatching and latching of control rod drive shafts includes drag testing of the associated rod cluster control assembly. 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 3.7.13, "Fuel Storage Pool Water Level."
ACTIONS	<u>A.1 and A.2</u> With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.6.1</u> 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).

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.6.1 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. Regulatory Guide 1.183, July 2000. 2. FSAR, Section 15.4.5. 3. NUREG-0800, Section 15.0.1. 4. 10 CFR 50.67.