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Palisades Nuclear Plant
Operated by Nuclear Management Company, LLC

August 22, 2005

Technical Specification 5.5.12.d

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Palisades Nuclear Plant
Docket 50-255
License No. DPR-20

Report of Changes to Technical Specifications Bases

This report is submitted in accordance with Palisades Technical Specification 5.5.12.d, which requires that changes to the Technical Specifications Bases, implemented without prior Nuclear Regulatory Commission (NRC) approval, be provided to the NRC on a frequency consistent with 10 CFR 50.71(e). Enclosure 1 provides a listing of all bases changes since issuance of the previous report, dated September 2, 2004, and identifies the affected sections and nature of the changes. Enclosure 2 provides page change instructions and a copy of the current Technical Specifications Bases List of Effective Pages, Title Page, Table of Contents, and the revised Technical Specification Bases sections listed in Enclosure 1.

Summary of Commitments

This letter contains no new commitments and no revisions to existing commitments.

Paul A. Harden
Site Vice-President, Palisades Nuclear Plant
Nuclear Management Company, LLC

Enclosures (2)

CC Administrator, Region III, USNRC
Project Manager, Palisades, USNRC
Resident Inspector, Palisades, USNRC

A001

ENCLOSURE 1
TECHNICAL SPECIFICATION BASES CHANGE CHRONOLOGY

DATE	AFFECTED SECTION(S)	CHANGE(S)
01/27/05	B 3.4.3	Make Bases consistent with NRC approved amendment 218 (cooldown rate limits for repaired reactor head).
02/24/05	B 3.0 B 3.3.1 B 3.3.3 B 3.3.7 B 3.3.8 B 3.4.11 B 3.4.12 B 3.4.15 B 3.4.16 B 3.6.7 B 3.7.4 B 3.7.5 B 3.8.1	Make Bases consistent with NRC approved amendment 219 (increased flexibility in mode restraints, TSTF-359).
04/19/05	B 3.3.7 B 3.6.7 (deleted)	Make Bases consistent with NRC approved amendment 221 (removal of hydrogen recombiners and hydrogen monitors from the Technical Specifications, TSTF-447).
06/07/05	B 3.7.7	Clarified non-safety related loads outside containment for component cooling water system.

ENCLOSURE 2

REVISED TECHNICAL SPECIFICATIONS BASES
Page Change Instructions
List of Effective Pages
Title Page
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B 3.0, B 3.3.1, B 3.3.3, B 3.3.7, B 3.3.8,
B 3.4.3, B 3.4.11, B 3.4.12, B 3.4.15, B 3.4.16,
B 3.7.4, B 3.7.5, B 3.7.7, B 3.8.1
(All pages are double-sided except Page Change Instructions and Title Page)

96 Pages Follow

TECHNICAL SPECIFICATIONS BASES CHANGES: September 2005
FACILITY OPERATING LICENSE DPR-20
DOCKET NO. 50-255
Page Change Instructions

Revise your copy of the Palisades Technical Specifications Bases with the attached revised pages. The revised pages are identified by amendment number or revision date at the bottom of the pages and contain vertical lines in the margin indicating the areas of change.

REMOVE	INSERT
List of Effective Pages	List of Effective Pages
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Section B 3.4.15	Section B 3.4.15
Section B 3.4.16	Section B 3.4.16
Section B 3.6.7	No replacement
Section B 3.7.4	Section B 3.7.4
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Section B 3.7.7	Section B 3.7.7
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PALISADES PLANT

FACILITY OPERATING LICENSE DPR-20

APPENDIX A

TECHNICAL SPECIFICATIONS

BASES

As Amended Through Amendment No. 221

Revised 04/19/2005

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCO	LCO 3.0.1 through LCO 3.0.7 establish the general requirements applicable to all Specifications and apply at all times unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the plant is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

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

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

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

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits.

If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the plant 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.)

BASES

LCO 3.0.2 (continued)

The second type of Required Action specifies the remedial measures that permit continued operation of the plant that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

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

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even 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, "PCS 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 plant 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 plant 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 plant. 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 plant 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 plant operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the plant, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Primary 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.

BASES

LCO 3.0.3 (continued)

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

a. The LCO is now met.

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

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

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in MODE 5 when a shutdown is required during MODE 1 operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 29 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 31 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the plant 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 plant shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the plant. An example of this is in LCO 3.7.14, "Spent Fuel Pool Water Level."

BASES

LCO 3.0.3 (continued)	LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the plant in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in spent fuel pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

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

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the plant 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 plant before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

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

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope.

BASES

LCO 3.0.4 (continued)

The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

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

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

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

BASES

LCO 3.0.4 (continued)

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

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

BASES

LCO 3.0.5

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

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

b. The OPERABILITY of other equipment.

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

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

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

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant 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.

BASES

LCO 3.0.6 (continued)

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

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

Specification 5.5.13, "Safety Functions 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.

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.

BASES

LCO 3.0.7

Special tests and operations are required at various times over the plant's life to demonstrate performance characteristics, to perform maintenance activities, and to perform special evaluations. Because TS normally preclude these tests and operations, Special Test Exceptions (STEs) allow specified requirements to be changed or suspended under controlled conditions. STEs are included in applicable sections of the Specifications. Unless otherwise specified, all other TS requirements remain unchanged and in effect as applicable. This will ensure that all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed or suspended to perform the special test or operation will remain in effect.

The Applicability of an STE LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with STE LCO is optional.

A special test may be performed under either the provisions of the appropriate STE LCO or the other applicable TS requirements. If it is desired to perform the special test under the provisions of the STE LCO, the requirements of the STE LCO shall be followed. This includes the SRs specified in the STE LCO.

Some of the STE LCO require that one or more of the LCO for normal operation be met (i.e., meeting the STE LCO requires meeting the specified normal LCO). The Applicability, ACTIONS, and SRs of the specified normal LCO, however, are not required to be met in order to meet the STE LCO when it is in effect. This means that, upon failure to meet a specified normal LCO, the associated ACTIONS of the STE LCO apply, in lieu of the ACTIONS of the normal LCO. Exceptions to the above do exist. There are instances when the Applicability of the specified normal LCO must be met, where its ACTIONS must be taken, where certain of its Surveillances must be performed, or where all of these requirements must be met concurrently with the requirements of the STE LCO.

Unless the SRs of the specified normal LCO are suspended or changed by the special test, those SRs that are necessary to meet the specified normal LCO must be met prior to performing the special test. During the conduct of the special test, those Surveillances need not be performed unless specified by the ACTIONS or SRs of the STE LCO.

ACTIONS for STE LCO provide appropriate remedial measures upon failure to meet the STE LCO. Upon failure to meet these ACTIONS, suspend the performance of the special test and enter the ACTIONS for all LCOs that are then not met. Entry into LCO 3.0.3 may possibly be required, but this determination should not be made by considering only the failure to meet the ACTIONS of the STE LCO.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

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

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

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

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary plant 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.

An example of this process is:

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

SR 3.0.2

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

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is the Containment Leak Rate Testing Program.

BASES

SR 3.0.2 (continued)

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

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

SR 3.0.3

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

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

The basis for this delay period includes consideration of plant 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.

BASES

SR 3.0.3 (continued)

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

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

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

BASES

SR 3.0.3 (continued)

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

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

SR 3.0.4

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

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the plant.

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 of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

BASES

SR 3.0.4 (continued)

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

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

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protective System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor trip to protect against violating the acceptable fuel design limits and breaching the reactor coolant pressure boundary during Anticipated Operational Occurrences (AOOs). (As defined in 10 CFR 50, Appendix A, "Anticipated operational occurances mean those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power.") By tripping the reactor, the RPS also assists the Engineered Safety Features (ESF) systems in mitigating accidents.

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

The LSSS, defined in this Specification as the Allowable Values, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

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

- The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling;
- Fuel centerline melting shall not occur; and
- The Primary Coolant System (PCS) pressure SL of 2750 psia shall not be exceeded.

Maintaining the parameters within the above values ensures that the offsite dose will be within the 10 CFR 50 (Ref. 1) and 10 CFR 100 (Ref. 2) criteria during AOOs.

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the plant life. The acceptable limit during accidents is that the offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 (Ref. 2) limits. Different accident categories allow 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 RPS is segmented into four interconnected modules. These modules are:

- Measurement channels;
- RPS trip units;
- Matrix Logic; and
- Trip Initiation Logic.

This LCO addresses measurement channels and RPS trip units. It also addresses the automatic bypass removal feature for those trips with Zero Power Mode bypasses. The RPS Logic and Trip Initiation Logic are addressed in LCO 3.3.2, "Reactor Protective System (RPS) Logic and Trip Initiation." The role of the measurement channels, RPS trip units, and RPS Bypasses is discussed below.

Measurement Channels

Measurement channels, consisting of pressure switches, field transmitters, or process sensors and associated instrumentation, provide a measurable electronic signal based upon the physical characteristics of the parameter being measured.

With the exception of Hi Startup Rate, which employs two instrument channels, and Loss of Load, which employs a single pressure sensor, four identical measurement channels with electrical and physical separation are provided for each parameter used in the direct generation of trip signals. These are designated channels A through D. Some measurement channels provide input to more than one RPS trip unit within the same RPS channel. In addition, some measurement channels may also be used as inputs to Engineered Safety Features (ESF) bistables, and most provide indication in the control room.

BASES

BACKGROUND (continued)

Measurement Channels (continued)

In the case of Hi Startup Rate and Loss of Load, where fewer than four sensor channels are employed, the reactor trips provided are not relied upon by the plant safety analyses. The sensor channels do however, provide trip input signals to all four RPS channels.

When a channel monitoring a parameter exceeds a predetermined setpoint, indicating an abnormal condition, the bistable monitoring the parameter in that channel will trip. Tripping two or more channels of bistable trip units monitoring the same parameter de-energizes Matrix Logic, (addressed by LCO 3.3.2) which in turn de-energizes the Trip Initiation Logic. This causes all four DC clutch power supplies to de-energize, interrupting power to the control rod drive mechanism clutches, allowing the full length control rods to insert into the core.

For those trips relied upon in the safety analyses, three of the four measurement and trip unit channels can meet the redundancy and testability of GDC 21 in 10 CFR 50, Appendix A (Ref. 1). This LCO requires, however, that four channels be OPERABLE. The fourth channel provides additional flexibility by allowing one channel to be removed from service (trip channel bypassed) for maintenance or testing while still maintaining a minimum two-out-of-three logic.

Since no single failure will prevent a protective system actuation, this arrangement meets the requirements of IEEE Standard 279-1971 (Ref. 3).

Most of the RPS trips are generated by comparing a single measurement to a fixed bistable setpoint. Two trip Functions, Variable High Power Trip and Thermal Margin Low Pressure Trip, make use of more than one measurement to provide a trip.

The required RPS Trip Functions utilize the following input instrumentation:

- Variable High Power Trip (VHPT)

  The VHPT uses Q Power as its input. Q Power is the higher of NI power from the power range NI drawer and primary calorimetric power (ΔT power) based on PCS hot leg and cold leg temperatures. The measurement channels associated with the VHPT are the power range excore channels, and the PCS hot and cold leg temperature channels.

BASES

BACKGROUND (continued)

Measurement Channels

- Variable High Power Trip (VHPT) (continued)

  The Thermal Margin Monitors provide the complex signal processing necessary to calculate the TM/LP trip setpoint, VHPT trip setpoint and trip comparison, and Q Power calculation. On power decreases the VHPT setpoint tracks power levels downward so that it is always within a fixed increment above current power, subject to a minimum value.

  On power increases, the trip setpoint remains fixed unless manually reset, at which point it increases to the new setpoint, a fixed increment above Q Power at the time of reset, subject to a maximum value. Thus, during power escalation, the trip setpoint must be repeatedly reset to avoid a reactor trip.

- High Startup Rate Trip

  The High Startup Rate trip uses the wide range Nuclear Instruments (NIs) to provide an input signal. There are only two wide range NI channels. The wide range channel signal processing electronics are physically mounted in RPS cabinet channels C (NI-1/3) and D (NI-2/4). Separate bistable trip units mounted within the NI-1/3 wide range channel drawer supply High Startup Rate trip signals to RPS channels A and C. Separate bistable trip units mounted within the NI-2/4 wide range channel drawer provide High Startup Rate trip signals to RPS channels B and D.

- Low Primary Coolant Flow Trip

  The Low Primary Coolant Flow Trip utilizes 16 flow measurement channels which monitor the differential pressure across the primary side of the steam generators. Each RPS channel, A, B, C, and D, receives a signal which is the sum of four differential pressure signals. This totalized signal is compared with a setpoint in the RPS Low Flow bistable trip unit for that RPS channel.

BASES

BACKGROUND (continued)

Measurement Channels (continued)

- Low Steam Generator Level Trips

  There are two separate Low Steam Generator Level trips, one for each steam generator. Each Low Steam Generator Level trip monitors four level measurement channels for the associated steam generator, one for each RPS channel.

- Low Steam Generator Pressure Trips

  There are also two separate Low Steam Generator Pressure trips, one for each steam generator. Each Low Steam Generator Pressure trip monitors four pressure measurement channels for the associated steam generator, one for each RPS channel.

- High Pressurizer Pressure Trip

  The High Pressurizer Pressure Trip monitors four pressurizer pressure channels, one for each RPS channel.

- Thermal Margin Low Pressure (TM/LP) Trip

  The TM/LP Trip utilizes bistable trip units. Each of these bistable trip units receives a calculated trip setpoint from the Thermal Margin Monitor (TMM) and compares it to the measured pressurizer pressure signal. The TM/LP setpoint is based on Q power (the higher of NI power from the power range NI drawer, or ΔT power, based on PCS hot leg and cold leg temperatures) pressurizer pressure, PCS cold leg temperature, and Axial Shape Index. The TMM provide the complex signal processing necessary to calculate the TM/LP trip setpoint, TM/LP trip comparison signal, and Q Power.

BASES

BACKGROUND (continued)

Measurement Channels (continued)

- <u>Loss of Load Trip</u>

  The Loss of Load trip uses a single pressure switch, 63/AST-2, in the turbine auto stop oil circuit to sense a turbine trip for input to all four RPS auxiliary trip units. The Loss of Load Trip is actuated by turbine auxiliary relays 305L and 305R. Relay 305L provides input to RPS channels A and C; 305R to channels B and D. Relays 305L and 305R are energized on a turbine trip. Their inputs are the same as the inputs to the turbine solenoid trip valve, 20ET.

  If a turbine trip is generated by loss of auto stop oil pressure, auto stop oil pressure switch 63/AST-2 will actuate relays 305L and 305R and generate a reactor trip. If a turbine trip is generated by an input to the solenoid trip valve, relays 305L and 305R, which are wired in parallel, will also be actuated and will generate a reactor trip.

- <u>Containment High Pressure Trip</u>

  The Containment High Pressure Trip is actuated by four pressure switches, one for each RPS channel.

- <u>Zero Power Mode Bypass Automatic Removal</u>

  The Zero Power Bypass allows manually bypassing (i.e., disabling) four reactor trip functions, Low PCS Flow, Low SG A Pressure, Low SG B Pressure, and TM/LP (low PCS pressure), when reactor power (as indicated by the wide range nuclear instrument channels) is below 10^{-4}%. This bypassing is necessary to allow RPS testing and control rod drive mechanism testing when the reactor is shutdown and plant conditions would cause a reactor trip to be present.

  The Zero Power Mode Bypass removal interlock uses the wide range nuclear instruments (NIs) as measurement channels. There are only two wide range NI channels. Separate bistables are provided to actuate the bypass removal for each RPS channel. Bistables in the NI-1/3 channel provide the bypass removal function for RPS channels A and C; bistables in the NI-2/4 channel for RPS channels B and D.

BASES

BACKGROUND (continued)

Several measurement instrument channels provide more than one required function. Those sensors shared for RPS and ESF functions are identified in Table B 3.3.1-1. That table provides a listing of those shared channels and the Specifications which they affect.

RPS Trip Units

Two types of RPS trip units are used in the RPS cabinets; bistable trip units and auxiliary trip units:

A bistable trip unit receives a measured process signal from its instrument channel and compares it to a setpoint; the trip unit actuates three relays, with contacts in the Matrix Logic channels, when the measured signal is less conservative than the setpoint. They also provide local trip indication and remote annunciation.

An auxiliary trip unit receives a digital input (contacts open or closed); the trip unit actuates three relays, with contacts in the Matrix Logic channels, when the digital input is received. They also provide local trip indication and remote annunciation.

Each RPS channel has four auxiliary trip units and seven bistable trip units.

The contacts from these trip unit relays are arranged into six coincidence matrices, comprising the Matrix Logic. If bistable trip units monitoring the same parameter in at least two channels trip, the Matrix Logic will generate a reactor trip (two-out-of-four logic).

Four of the RPS measurement channels provide contact outputs to the RPS, so the comparison of an analog input to a trip setpoint is not necessary. In these cases, the bistable trip unit is replaced with an auxiliary trip unit. The auxiliary trip units provide contact multiplication so the single input contact opening can provide multiple contact outputs to the coincidence logic as well as trip indication and annunciation.

BASES

BACKGROUND (continued)

RPS Trip Units (continued)

Trips employing auxiliary trip units include the VHPT, which receives contact inputs from the Thermal Margin Monitors; the High Startup Rate trip which employs contact inputs from bistables mounted in the two wide range drawers; the Loss of Load Trip which receives contact inputs from one of two auxiliary relays which are operated by a single switch sensing turbine auto stop oil pressure; and the Containment High Pressure (CHP) trip, which employs containment pressure switch contacts.

There are four RPS trip units, designated as channels A through D, each channel having eleven trip units, one for each RPS Function. Trip unit output relays de-energize when a trip occurs.

All RPS Trip Functions, with the exception of the Loss of Load and CHP trips, generate a pretrip alarm as the trip setpoint is approached.

The Allowable Values are specified for each safety related RPS trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. The methodology used to determine the nominal trip setpoints is also provided in plant documents. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. A channel is inoperable if its actual setpoint is not within its Allowable Value.

Setpoints in accordance with the Allowable Value will ensure that SLs of Chapter 2.0 are not violated during AOOs and the consequences of DBAs will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed.

Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS.

BASES

BACKGROUND (continued)

Reactor Protective System Bypasses

Three different types of trip bypass are utilized in the RPS, Operating Bypass, Zero Power Mode Bypass, and Trip Channel Bypass. The Operating Bypass or Zero Power Mode Bypass prevent the actuation of a trip unit or auxiliary trip unit; the Trip Channel Bypass prevents the trip unit output from affecting the Logic Matrix. A channel which is bypassed, other than as allowed by the Table 3.3.1-1 footnotes, cannot perform its specified safety function and must be considered to be inoperable.

Operating Bypasses

The Operating Bypasses are initiated and removed automatically during startup and shutdown as power level changes. An Operating Bypass prevents the associated RPS auxiliary trip unit from receiving a trip signal from the associated measurement channel. With the bypass in place, neither the pre-trip alarm nor the trip will actuate if the measured parameter exceeds the set point. An annunciator is provided for each Operating Bypass. The RPS trips with Operating Bypasses are:

a. High Startup Rate Trip bypass. The High Startup Rate trip is automatically bypassed when the associated wide range channel indicates below 1E-4% RTP, and when the associated power range excore channel indicates above 13% RTP. These bypasses are automatically removed between 1E-4% RTP and 13% RTP.

b. Loss of Load bypass. The Loss of Load trip is automatically bypassed when the associated power range excore channel indicates below 17% RTP. The bypass is automatically removed when the channel indicates above the set point. The same power range excore channel bistable is used to bypass the High Startup Rate trip and the Loss of Load trip for that RPS channel.

BASES

BACKGROUND (continued)

Operating Bypasses (continued)

Each wide range channel contains two bistables set at 1E-4% RTP, one bistable unit for each associated RPS channel. Each of the two wide range channels affect the Operating Bypasses for two RPS channels; wide range channel NI-1/3 for RPS channels A and C, wide range channel NI-2/4 for RPS channels B and D. Each of the four power range excore channel affects the Operating Bypasses for the associated RPS channel. The power range excore channel bistables associated with the Operating Bypasses are set at a nominal 15%, and are required to actuate between 13% RTP and 17% RTP.

Zero Power Mode (ZPM) Bypass

The ZPM Bypass is used when the plant is shut down and it is desired to raise the control rods for control rod drop testing with PCS flow, pressure or temperature too low for the RPS trips to be reset. ZPM bypasses may be manually initiated and removed when wide range power is below 1E-4% RTP, and are automatically removed if the associated wide range NI indicated power exceeds 1E-4% RTP. A ZPM bypass prevents the RPS trip unit from actuating if the measured parameter exceeds the set point. Operation of the pretrip alarm is unaffected by the zero power mode bypass. An annunciator indicates the presence of any ZPM bypass. The RPS trips with ZPM bypasses are:

a. Low Primary Coolant System Flow.

b. Low Steam Generator Pressure.

c. Thermal Margin/Low Pressure.

The wide range NI channels provide contact closure permissive signals when indicated power is below 1E-4% RTP. The ZPM bypasses may then be manually initiated or removed by actuation of key-lock switches. One key-lock switch located on each RPS cabinet controls the ZPM Bypass for the associated RPS trip channels. The bypass is automatically removed if the associated wide range NI indicated power exceeds 1E-4% RTP. The same wide range NI channel bistables that provide the ZPM Bypass permissive and removal signals also provide the high startup rate trip Operating Bypass actuation and removal.

BASES

BACKGROUND (continued)

Trip Channel Bypass

A Trip Channel Bypass is used when it is desired to physically remove an individual trip unit from the system, or when calibration or servicing of a trip channel could cause an inadvertent trip. A trip Channel Bypass may be manually initiated or removed at any time by actuation of a key-lock switch. A Trip Channel Bypass prevents the trip unit output from affecting the RPS logic matrix. A light above the bypass switch indicates that the trip channel has been bypassed. Each RPS trip unit has an associated trip channel bypass:

The key-lock trip channel bypass switch is located above each trip unit. The key cannot be removed when in the bypass position. Only one key for each trip parameter is provided, therefore the operator can bypass only one channel of a given parameter at a time. During the bypass condition, system logic changes from two-out-of-four to two-out-of-three channels required for trip.

APPLICABLE SAFETY ANALYSES

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in Reference 4 takes credit for most RPS trip Functions. The High Startup Rate and Loss of Load Functions, which are not specifically credited in the accident analysis are part of the NRC approved licensing basis for the plant. The High Startup Rate and Loss of Load trips are purely equipment protective, and their use minimizes the potential for equipment damage.

The specific safety analyses applicable to each protective Function are identified below.

1. Variable High Power Trip (VHPT)

The VHPT provides reactor core protection against positive reactivity excursions.

The safety analysis assumes that this trip is OPERABLE to terminate excessive positive reactivity insertions during power operation and while shut down.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

2. High Startup Rate Trip

There are no safety analyses which take credit for functioning of the High Startup Rate Trip. The High Startup Rate trip is used to trip the reactor when excore wide range power indicates an excessive rate of change. The High Startup Rate trip minimizes transients for events such as a continuous control rod withdrawal or a boron dilution event from low power levels. The trip may be operationally bypassed when THERMAL POWER is < 1E-4% RTP, when poor counting statistics may lead to erroneous indication. It may also be operationally bypassed at > 13% RTP, where moderator temperature coefficient and fuel temperature coefficient make high rate of change of power unlikely.

There are only two wide range drawers, with each supplying contact input to auxiliary trip units in two RPS channels.

3. Low Primary Coolant System Flow Trip

The Low PCS Flow trip provides DNB protection during events which suddenly reduce the PCS flow rate during power operation, such as loss of power to, or seizure of, a primary coolant pump.

Flow in each of the four PCS loops is determined from pressure drop from inlet to outlet of the SGs. The total PCS flow is determined, for the RPS flow channels, by summing the loop pressure drops across the SGs and correlating this pressure sum with the sum of SG differential pressures which exist at 100% flow (four pump operation at full power T_{ave}). Full PCS flow is that flow which exists at RTP, at full power T_{ave}, with four pumps operating.

4, 5. Low Steam Generator Level Trip

The Low Steam Generator Level trips are provided to trip the reactor in the event of excessive steam demand (to prevent overcooling the PCS) and loss of feedwater events (to prevent overpressurization of the PCS).

The Allowable Value assures that there will be sufficient water inventory in the SG at the time of trip to allow a safe and orderly plant shutdown and to prevent SG dryout assuming minimum AFW capacity.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

4, 5. Low Steam Generator Level Trip (continued)

Each SG level is sensed by measuring the differential pressure in the upper portion of the downcomer annulus in the SG. These trips share four level sensing channels on each SG with the AFW actuation signal.

6, 7. Low Steam Generator Pressure Trip

The Low Steam Generator Pressure trip provides protection against an excessive rate of heat extraction from the steam generators, which would result in a rapid uncontrolled cooldown of the PCS. This trip provides a mitigation function in the event of an MSLB.

The Low SG Pressure channels are shared with the Low SG Pressure signals which isolate the steam and feedwater lines.

8. High Pressurizer Pressure Trip

The High Pressurizer Pressure trip, in conjunction with pressurizer safety valves and Main Steam Safety Valves (MSSVs), provides protection against overpressure conditions in the PCS when at operating temperature. The safety analyses assume the High Pressurizer Pressure trip is OPERABLE during accidents and transients which suddenly reduce PCS cooling (e.g., Loss of Load, Main Steam Isolation Valve (MSIV) closure, etc.) or which suddenly increase reactor power (e.g., rod ejection accident).

The High Pressurizer Pressure trip shares four safety grade instrument channels with the TM/LP trip, Anticipated Transient Without Scram (ATWS) and PORV circuits, and the Pressurizer Low Pressure Safety Injection Signal.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

9. Thermal Margin/Low Pressure (TM/LP) Trip

The TM/LP trip is provided to prevent reactor operation when the DNBR is insufficient. The TM/LP trip protects against slow reactivity or temperature increases, and against pressure decreases.

The trip is initiated whenever the PCS pressure signal drops below a minimum value (P_{min}) or a computed value (P_{var}) as described below, whichever is higher.

The TM/LP trip uses Q Power, ASI, pressurizer pressure, and cold leg temperature (T_c) as inputs.

Q Power is the higher of core THERMAL POWER (ΔT Power) or nuclear power. The ΔT power uses hot leg and cold leg RTDs as inputs. Nuclear power uses the power range excore channels as inputs. Both the ΔT and excore power signals have provisions for calibration by calorimetric calculations.

The ASI is calculated from the upper and lower power range excore detector signals, as explained in Section 1.1, "Definitions." The signal is corrected for the difference between the flux at the core periphery and the flux at the detectors.

The T_c value is the higher of the two cold leg signals.

The Low Pressurizer Pressure trip limit (P_{var})is calculated using the equations given in Table 3.3.1-2.

The calculated limit (P_{var}) is then compared to a fixed Low Pressurizer Pressure trip limit (P_{min}). The auctioneered highest of these signals becomes the trip limit (P_{trip}). P_{trip} is compared to the measured PCS pressure and a trip signal is generated when the measured pressure for that channel is less than or equal to P_{trip}. A pre-trip alarm is also generated when P is less than or equal to the pre-trip setting, $P_{trip} + \Delta P$.

The TM/LP trip setpoint is a complex function of these inputs and represents a minimum acceptable PCS pressure for the existing temperature and power conditions. It is compared to actual PCS pressure in the TM/LP trip unit.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

10. Loss of Load Trip

There are no safety analyses which take credit for functioning of the Loss of Load Trip.

The Loss of Load trip is provided to prevent lifting the pressurizer and main steam safety valves in the event of a turbine generator trip while at power. The trip is equipment protective. The safety analyses do not assume that this trip functions during any accident or transient. The Loss of Load trip uses a single pressure switch in the turbine auto stop oil circuit to sense a turbine trip for input to all four RPS auxiliary trip units.

11. Containment High Pressure Trip

The Containment High Pressure trip provides a reactor trip in the event of a Loss of Coolant Accident (LOCA) or Main Steam Line Break (MSLB). The Containment High Pressure trip shares sensors with the Containment High Pressure sensing logic for Safety Injection, Containment Isolation, and Containment Spray. Each of these sensors has a single bellows which actuates two microswitches. One microswitch on each of four sensors provides an input to the RPS.

12. Zero Power Mode Bypass Removal

The only RPS bypass considered in the safety analyses is the Zero Power Mode (ZPM) Bypass. The ZPM Bypass is used when the plant is shut down and it is desired to raise the control rods for control rod drop testing with PCS flow or temperature too low for the RPS Low PCS Flow, Low SG Pressure, or Thermal Margin/Low Pressure trips to be reset. ZPM bypasses are automatically removed if the wide range NI indicated power exceeds 1E-4% RTP.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

12. Zero Power Mode Bypass Removal (continued)

The safety analyses take credit for automatic removal of the ZPM Bypass if reactor criticality due to a Continuous Control Rod Bank Withdrawal should occur with the affected trips bypassed and PCS flow, pressure, or temperature below the values at which the RPS could be reset. The ZPM Bypass would effectively be removed when the first wide range NI channel indication reached 1E-4% RTP. With the ZPM Bypass for two RPS channels removed, the RPS would trip on one of the un-bypassed trips. This would prevent the reactor reaching an excessive power level.

If a reactor criticality due to a Continuous Control Rod Bank Withdrawal should occur when PCS flow, steam generator pressure, and PCS pressure (TM/LP) were above their trip setpoints, a trip would terminate the event when power increased to the minimum setting (nominally 30%) of the Variable High Power Trip. In this case, the monitored parameters are at or near their normal operational values, and a trip initiated at 30% RTP provides adequate protection.

The RPS design also includes automatic removal of the Operating Bypasses for the High Startup Rate and Loss of Load trips. The safety analyses do not assume functioning of either these trips or the automatic removal of their bypasses.

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

LCO

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of the trip unit (including its output relays), any required portion of the associated instrument channel, or both, renders the affected channel(s) inoperable and reduces the reliability of the affected Functions. Failure of an automatic ZPM bypass removal channel may also impact the associated instrument channel(s) and reduce the reliability of the affected Functions.

BASES

LCO (continued)

Actions allow Trip Channel Bypass of individual channels, but the bypassed channel must be considered to be inoperable. The bypass key used to bypass a single channel cannot be simultaneously used to bypass that same parameter in other channels. This interlock prevents operation with more than one channel of the same Function trip channel bypassed. The plant is normally restricted to 7 days in a trip channel bypass, or otherwise inoperable condition before either restoring the Function to four channel operation (two-out-of-four logic) or placing the channel in trip (one-out-of-three logic).

The Allowable Values are specified for each safety related RPS trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. Neither Allowable Values nor setpoints are specified for the non-safety related RPS Trip Functions, since no safety analysis assumptions would be violated if they are not set at a particular value.

The following Bases for each trip Function identify the above RPS trip Function criteria items that are applicable to establish the trip Function OPERABILITY.

1. Variable High Power Trip (VHPT)

   This LCO requires all four channels of the VHPT Function to be OPERABLE.

   The Allowable Value is high enough to provide an operating envelope that prevents unnecessary VHPT trips during normal plant operations. The Allowable Value is low enough for the system to function adequately during reactivity addition events.

BASES

LCO (continued)

1. Variable High Power Trip (VHPT) (continued)

The VHPT is designed to limit maximum reactor power to its maximum design and to terminate power excursions initiating at lower powers without power reaching this full power limit. During plant startup, the VHPT trip setpoint is initially at its minimum value, ≤ 30%. Below 30% RTP, the VHPT setpoint is not required to "track" with Q Power, i.e., be adjusted to within 15% RTP. It remains fixed until manually reset, at which point it increases to ≤ 15% above existing Q Power.

The maximum allowable setting of the VHPT is 109.4% RTP. Adding to this the possible variation in trip setpoint due to calibration and instrument error, the maximum actual steady state power at which a trip would be actuated is 113.4%, which is the value assumed in the safety analysis.

2. High Startup Rate Trip

This LCO requires four channels of High Startup Rate Trip Function to be OPERABLE in MODES 1 and 2.

The High Startup Rate trip serves as a backup to the administratively enforced startup rate limit. The Function is not credited in the accident analyses; therefore, no Allowable Value for the trip or operating bypass Functions is derived from analytical limits and none is specified.

The four channels of the High Startup Rate trip are derived from two wide range NI signal processing drawers. Thus, a failure in one wide range channel could render two RPS channels inoperable. It is acceptable to continue operation in this condition because the High Startup Rate trip is not credited in any safety analyses.

The requirement for this trip Function is modified by a footnote, which allows the High Startup Rate trip to be bypassed when the wide range NI indicates below 10E-4% or when THERMAL POWER is above 13% RTP. If a High Startup Rate trip is bypassed when power is between these limits, it must be considered to be inoperable.

BASES

LCO (continued)

3. Low Primary Coolant System Flow Trip

This LCO requires four channels of Low PCS Flow Trip Function to be OPERABLE.

This trip is set high enough to maintain fuel integrity during a loss of flow condition. The setting is low enough to allow for normal operating fluctuations from offsite power.

The Low PCS Flow trip setpoint of 95% of full PCS flow insures that the reactor cannot operate when the flow rate is less than 93% of the nominal value considering instrument errors. Full PCS flow is that flow which exists at RTP, at full power Tave, with four pumps operating.

The requirement for this trip Function is modified by a footnote, which allows use of the ZPM bypass when wide range power is below 1E-4% RTP. That bypass is automatically removed when the associated wide range channel indicates 1E-4% RTP. If a trip channel is bypassed when power is above 1E-4% RTP, it must be considered to be inoperable.

4, 5. Low Steam Generator Level Trip

This LCO requires four channels of Low Steam Generator Level Trip Function per steam generator to be OPERABLE.

The 25.9% Allowable Value assures that there is an adequate water inventory in the steam generators when the reactor is critical and is based upon narrow range instrumentation. The 25.9% indicated level corresponds to the location of the feed ring.

6, 7. Low Steam Generator Pressure Trip

This LCO requires four channels of Low Steam Generator Pressure Trip Function per steam generator to be OPERABLE.

The Allowable Value of 500 psia is sufficiently below the full load operating value for steam pressure so as not to interfere with normal plant operation, but still high enough to provide the required protection in the event of excessive steam demand. Since excessive steam demand causes the PCS to cool down, resulting in positive reactivity addition to the core, a reactor trip is required to offset that effect.

BASES

LCO
(continued)

8. High Pressurizer Pressure Trip

This LCO requires four channels of High Pressurizer Pressure Trip Function to be OPERABLE.

The Allowable Value is set high enough to allow for pressure increases in the PCS during normal operation (i.e., plant transients) not indicative of an abnormal condition. The setting is below the lift setpoint of the pressurizer safety valves and low enough to initiate a reactor trip when an abnormal condition is indicated.

9. Thermal Margin/Low Pressure (TM/LP) Trip

This LCO requires four channels of TM/LP Trip Function to be OPERABLE.

The TM/LP trip setpoints are derived from the core thermal limits through application of appropriate allowances for measurement uncertainties and processing errors. The allowances specifically account for instrument drift in both power and inlet temperatures, calorimetric power measurement, inlet temperature measurement, and primary system pressure measurement.

Other uncertainties including allowances for assembly power tilt, fuel pellet manufacturing tolerances, core flow measurement uncertainty and core bypass flow, inlet temperature measurement time delays, and ASI measurement, are included in the development of the TM/LP trip setpoint used in the accident analysis.

The requirement for this trip Function is modified by a footnote, which allows use of the ZPM bypass when wide range power is below 1E-4% RTP. That bypass is automatically removed when the associated wide range channel indicates 1E-4% RTP. If a trip channel is bypassed when power is above 1E-4% RTP, it must be considered to be inoperable.

BASES

LCO (continued)

10. Loss of Load Trip

The LCO requires four Loss of Load Trip Function channels to be OPERABLE in MODE 1 with THERMAL POWER ≥ 17% RTP.

The Loss of Load trip may be bypassed or be inoperable with THERMAL POWER < 17% RTP, since it is no longer needed to prevent lifting of the pressurizer safety valves or steam generator safety valves in the event of a Loss of Load. Loss of Load Trip unit must be considered inoperable if it is bypassed when THERMAL POWER is above 17% RTP.

This LCO requires four RPS Loss of Load auxiliary trip units, relays 305L and 305R, and pressure switch 63/AST-2 to be OPERABLE. With those components OPERABLE, a turbine trip will generate a reactor trip. The LCO does not require the various turbine trips, themselves, to be OPERABLE.

The Nuclear Steam Supply System and Steam Dump System are capable of accommodating the Loss of Load without requiring the use of the above equipment.

The Loss of Load Trip Function is not credited in the accident analysis; therefore, an Allowable Value for the trip cannot be derived from analytical limits, and is not specified.

11. Containment High Pressure Trip

This LCO requires four channels of Containment High Pressure Trip Function to be OPERABLE.

The Allowable Value is high enough to allow for small pressure increases in containment expected during normal operation (i.e., plant heatup) that are not indicative of an abnormal condition. The setting is low enough to initiate a reactor trip to prevent containment pressure from exceeding design pressure following a DBA and ensures the reactor is shutdown before initiation of safety injection and containment spray.

BASES

LCO (continued)

12. ZPM Bypass

The LCO requires that four channels of automatic Zero Power Mode (ZPM) Bypass removal instrumentation be OPERABLE. Each channel of automatic ZPM Bypass removal includes a shared wide range NI channel, an actuating bistable in the wide range drawer, and a relay in the associated RPS cabinet. Wide Range NI channel 1/3 is shared between ZPM Bypass removal channels A and C; Wide Range NI channel 2/4, between ZPM Bypass removal channels B and D. An operable bypass removal channel must be capable of automatically removing the capability to bypass the affected RPS trip channels with the ZPM Bypass key switch at the proper setpoint.

APPLICABILITY

This LCO requires all safety related trip functions to be OPERABLE in accordance with Table 3.3.1-1.

Those RPS trip Functions which are assumed in the safety analyses (all except High Startup Rate and Loss of Load), are required to be operable in MODES 1 and 2, and in MODES 3, 4, and 5 with more than one full-length control rod capable of being withdrawn and PCS boron concentration less than REFUELING BORON CONCENTRATION.

These trip Functions are not required while in MODES 3, 4, or 5, if PCS boron concentration is at REFUELING BORON CONCENTRATION, or when no more than one full-length control rod is capable of being withdrawn, because the RPS Function is already fulfilled. REFUELING BORON CONCENTRATION provides sufficient negative reactivity to assure the reactor remains subcritical regardless of control rod position, and the safety analyses assume that the highest worth withdrawn full-length control rod will fail to insert on a trip. Therefore, under these conditions, the safety analyses assumptions will be met without the RPS trip Function.

The High Startup Rate Trip Function is required to be OPERABLE in MODES 1 and 2, but may be bypassed when the associated wide range NI channel indicates below 1E-4% power, when poor counting statistics may lead to erroneous indication. In MODES 3, 4, 5, and 6, the High Startup Rate trip is not required to be OPERABLE. Wide range channels are required to be OPERABLE in MODES 3, 4, and 5, by LCO 3.3.9, "Neutron Flux Monitoring Channels," and in MODE 6, by LCO 3.9.2, "Nuclear Instrumentation."

BASES

APPLICABILITY (continued)

The High Startup Rate Trip Function is required to be OPERABLE in MODES 1 and 2, but may be bypassed when the associated wide range NI channel indicates below 1E-4% power, when poor counting statistics may lead to erroneous indication. In MODES 3, 4, 5, and 6, the High Startup Rate trip is not required to be OPERABLE. Wide range channels are required to be OPERABLE in MODES 3, 4, and 5, by LCO 3.3.9, "Neutron Flux Monitoring Channels," and in MODE 6, by LCO 3.9.2, "Nuclear Instrumentation."

The Loss of Load trip is required to be OPERABLE with THERMAL POWER at or above 17% RTP. Below 17% RTP, the ADVs are capable of relieving the pressure due to a Loss of Load event without challenging other overpressure protection.

The trips are designed to take the reactor subcritical, maintaining the SLs during AOOs and assisting the ESF in providing acceptable consequences during accidents.

ACTIONS

The most common causes of channel inoperability are outright failure of loop components or drift of those loop components which is sufficient to exceed the tolerance provided in the plant setpoint analysis. Loop component failures are typically identified by the actuation of alarms due to the channel failing to the "safe" condition, during CHANNEL CHECKS (when the instrument is compared to the redundant channels), or during the CHANNEL FUNCTIONAL TEST (when an automatic component might not respond properly). Typically, the drift of the loop components is found to be small and results in a delay of actuation rather than a total loss of function. Excessive loop component drift would, most likely, be identified during a CHANNEL CHECK (when the instrument is compared to the redundant channels) or during a CHANNEL CALIBRATION (when instrument loop components are checked against reference standards).

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 RPS bistable trip unit is found inoperable, all affected Functions provided by that channel must be declared inoperable, and the plant must enter the Condition for the particular protection Functions affected.

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip Function exceeds that specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 is immediately entered if applicable in the current MODE of operation.

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 Function. The Completion Times of each inoperable Function will be tracked separately for each Function, starting from the time the Condition was entered.

A.1

Condition A applies to the failure of a single channel in any required RPS Function, except High Startup Rate, Loss of Load, or ZPM Bypass Removal. (Condition A is modified by a Note stating that this Condition does not apply to the High Startup Rate, Loss of Load, or ZPM Bypass Removal Functions. The failure of one channel of those Functions is addressed by Conditions B, C, or D.)

If one RPS bistable trip unit or associated instrument channel is inoperable, operation is allowed to continue. Since the trip unit and associated instrument channel combine to perform the trip function, this Condition is also appropriate if both the trip unit and the associated instrument channel are inoperable. Though not required, the inoperable channel may be bypassed. The provision of four trip channels allows one channel to be bypassed (removed from service) during operations, placing the RPS in two-out-of-three coincidence logic. The failed channel must be restored to OPERABLE status or placed in trip within 7 days.

Required Action A.1 places the Function in a one-out-of-three configuration. In this configuration, common cause failure of dependent channels cannot prevent trip.

The Completion Time of 7 days is based on operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

BASES

ACTIONS (continued)

A.1 (continued)

The Completion Time of 7 days is based on operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

B.1

Condition B applies to the failure of a single High Startup Rate trip unit or associated instrument channel.

If one trip unit or associated instrument channel fails, it must be restored to OPERABLE status prior to entering MODE 2 from MODE 3. A shutdown provides the appropriate opportunity to repair the trip function and conduct the necessary testing. The Completion Time is based on the fact that the safety analyses take no credit for the functioning of this trip.

C.1

Condition C applies to the failure of a single Loss of Load or associated instrument channel.

If one trip unit or associated instrument channel fails, it must be restored to OPERABLE status prior to THERMAL POWER ≥ 17% RTP following a shutdown. If the plant is shutdown at the time the channel becomes inoperable, then the failed channel must be restored to OPERABLE status prior to THERMAL POWER ≥ 17% RTP. For this Completion Time, "following a shutdown" means this Required Action does not have to be completed until prior to THERMAL POWER ≥ 17% RTP for the first time after the plant has been in MODE 3 following entry into the Condition. The Completion Time trip assures that the plant will not be restarted with an inoperable Loss of Load trip channel.

BASES

ACTIONS (continued)

D.1 and D.2

Condition D applies when one or more automatic ZPM Bypass removal channels are inoperable. If the ZPM Bypass removal channel cannot be restored to OPERABLE status, the affected ZPM Bypasses must be immediately removed, or the bypassed RPS trip Function channels must be immediately declared to be inoperable. Unless additional circuit failures exist, the ZPM Bypass may be removed by placing the associated "Zero Power Mode Bypass" key operated switch in the normal position.

A trip channel which is actually bypassed, other than as allowed by the Table 3.3.1-1 footnotes, cannot perform its specified safety function and must immediately be declared to be inoperable.

E.1 and E.2

Condition E applies to the failure of two channels in any RPS Function, except ZPM Bypass Removal Function. (The failure of ZPM Bypass Removal Functions is addressed by Condition D.).

Condition E is modified by a Note stating that this Condition does not apply to the ZPM Bypass Removal Function.

Required Action E.1 provides for placing one inoperable channel in trip within the Completion Time of 1 hour. Though not required, the other inoperable channel may be (trip channel) bypassed.

BASES

ACTIONS (continued)

E.1 and E.2 (continued)

This Completion Time is sufficient to allow the operator to take all appropriate actions for the failed channels while ensuring that the risk involved in operating with the failed channels is acceptable. With one channel of protective instrumentation bypassed or inoperable in an untripped condition, the RPS is in a two-out-of-three logic for that function; but with another channel failed, the RPS may be operating in a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, one of the inoperable channels is placed in trip. This places the RPS in a one-out-of-two for that function logic. If any of the other unbypassed channels for that function receives a trip signal, the reactor will trip.

Action E.2 is modified by a Note stating that this Action does not apply to (is not required for) the High Startup Rate and Loss of Load Functions.

One channel is required to be restored to OPERABLE status within 7 days for reasons similar to those stated under Condition A. After one channel is restored to OPERABLE status, the provisions of Condition A still apply to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action E.2 must be placed in trip if more than 7 days have elapsed since the initial channel failure.

F.1

The power range excore channels are used to generate the internal ASI signal used as an input to the TM/LP trip. They also provide input to the Thermal Margin Monitors for determination of the Q Power input for the TM/LP trip and the VHPT. If two power range excore channels cannot be restored to OPERABLE status, power is restricted or reduced during subsequent operations because of increased uncertainty associated with inoperable power range excore channels which provide input to those trips.

The Completion Time of 2 hours is adequate to reduce power in an orderly manner without challenging plant systems.

BASES

ACTIONS (continued)

G.1, G.2.1, and G.2.2

Condition G is entered when the Required Action and associated Completion Time of Condition A, B, C, D, E, or F are not met, or if the control room ambient air temperature exceeds 90°F.

If the control room ambient air temperature exceeds 90°F, all Thermal Margin Monitor channels are rendered inoperable because their operating temperature limit is exceeded. In this condition, or if the Required Actions and associated Completion Times are not met, the reactor must be placed in a condition in which the LCO does not apply. To accomplish this, the plant must be placed in MODE 3, with no more than one full-length control rod capable of being withdrawn or with the PCS boron concentration at REFUELING BORON CONCENTRATION in 6 hours.

The Completion Time is reasonable, based on operating experience, for placing the plant in MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The Completion Time is also reasonable to ensure that no more than one full-length control rod is capable of being withdrawn or that the PCS boron concentration is at REFUELING BORON CONCENTRATION.

SURVEILLANCE REQUIREMENTS

The SRs for any particular RPS Function are found in the SR column of Table 3.3.1-1 for that Function. Most Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. Under most conditions, 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1 (continued)

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

The Containment High Pressure and Loss of Load channels are pressure switch actuated. As such, they have no associated control room indicator and do not require a CHANNEL CHECK.

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

SR 3.3.1.2

This SR verifies that the control room ambient air temperature is within the environmental qualification temperature limits for the most restrictive RPS components, which are the Thermal Margin Monitors. These monitors provide input to both the VHPT Function and the TM/LP Trip Function. The 12 hour Frequency is reasonable based on engineering judgement and plant operating experience.

SR 3.3.1.3

A daily calibration (heat balance) is performed when THERMAL POWER is ≥ 15%. The daily calibration consists of adjusting the "nuclear power calibrate" potentiometers to agree with the calorimetric calculation if the absolute difference is ≥ 1.5%. Nuclear power is adjusted via a potentiometer, or THERMAL POWER is adjusted via a Thermal Margin Monitor bias number, as necessary, in accordance with the daily calibration (heat balance) procedure. Performance of the daily calibration ensures that the two inputs to the Q power measurement are indicating accurately with respect to the much more accurate secondary calorimetric calculation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.3 (continued)

The Frequency of 24 hours is based on plant operating experience and takes into account indications and alarms located in the control room to detect deviations in channel outputs.

The Frequency is modified by a Note indicating this Surveillance must be performed within 12 hours after THERMAL POWER is ≥ 15% RTP. The secondary calorimetric is inaccurate at lower power levels. The 12 hours allows time requirements for plant stabilization, data taking, and instrument calibration.

SR 3.3.1.4

It is necessary to calibrate the power range excore channel upper and lower subchannel amplifiers such that the measured ASI reflects the true core power distribution as determined by the incore detectors. ASI is utilized as an input to the TM/LP trip function where it is used to ensure that the measured axial power profiles are bounded by the axial power profiles used in the development of the T_{inlet} limitation of LCO 3.4.1. An adjustment of the excore channel is necessary only if reactor power is greater than 25% RTP and individual excore channel ASI differs from AXIAL OFFSET, as measured by the incores, outside the bounds of the following table:

Allowed Reactor Power	Group 4 Rods ≥ 128" withdrawn	Group 4 Rods <128" withdrawn
≤ 100%	-0.020 ≤ (AO-ASI) ≤ 0.020	-0.040 ≤ (AO-ASI) ≤ 0.040
< 95	-0.033 ≤ (AO-ASI) ≤ 0.020	-0.053 ≤ (AO-ASI) ≤ 0.040
< 90	-0.046 ≤ (AO-ASI) ≤ 0.020	-0.066 ≤ (AO-ASI) ≤ 0.040
< 85	-0.060 ≤ (AO-ASI) ≤ 0.020	-0.080 ≤ (AO-ASI) ≤ 0.040
< 80	-0.120 ≤ (AO-ASI) ≤ 0.080	-0.140 ≤ (AO-ASI) ≤ 0.100
< 75	-0.120 ≤ (AO-ASI) ≤ 0.080	-0.140 ≤ (AO-ASI) ≤ 0.100
< 70	-0.120 ≤ (AO-ASI) ≤ 0.080	-0.140 ≤ (AO-ASI) ≤ 0.100
< 65	-0.120 ≤ (AO-ASI) ≤ 0.080	-0.140 ≤ (AO-ASI) ≤ 0.100
< 60	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 55	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 50	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 45	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 40	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 35	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 30	-0.160 ≤ (AO-ASI) ≤ 0.120	-0.180 ≤ (AO-ASI) ≤ 0.140
< 25	Below 25% RTP any AO/ASI difference is acceptable	

Table values determined with a conservative P_{var} gamma constant of −9505.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4 (continued)

Below 25% RTP any difference between ASI and AXIAL OFFSET is acceptable. A Note indicates the Surveillance is not required to have been performed until 12 hours after THERMAL POWER is ≥ 25% RTP. Uncertainties in the excore and incore measurement process make it impractical to calibrate when THERMAL POWER is < 25% RTP. The 12 hours allows time for plant stabilization, data taking, and instrument calibration.

The 31 day Frequency is adequate, based on operating experience of the excore linear amplifiers and the slow burnup of the detectors. The excore readings are a strong function of the power produced in the peripheral fuel bundles and do not represent an integrated reading across the core. Slow changes in neutron flux during the fuel cycle can also be detected at this Frequency.

SR 3.3.1.5

A CHANNEL FUNCTIONAL TEST is performed on each RPS instrument channel, except Loss of Load and High Startup Rate, every 92 days to ensure the entire channel will perform its intended function when needed. For the TM/LP Function, the constants associated with the Thermal Margin Monitors must be verified to be within tolerances.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment must be consistent with the assumptions of the current setpoint analysis.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

A calibration check of the power range excore channels using the internal test circuitry is required every 92 days. This SR uses an internally generated test signal to check that the 0% and 50% levels read within limits for both the upper and lower detector, both on the analog meter and on the TMM screen. This check verifies that neither the zero point nor the amplifier gain adjustment have undergone excessive drift since the previous complete CHANNEL CALIBRATION.

The Frequency of 92 days is acceptable, based on plant operating experience, and takes into account indications and alarms available to the operator in the control room.

SR 3.3.1.7

A CHANNEL FUNCTIONAL TEST on the Loss of Load and High Startup Rate channels is performed prior to a reactor startup to ensure the entire channel will perform its intended function.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The High Startup Rate trip is actuated by either of the Wide Range Nuclear Instrument Startup Rate channels. NI-1/3 sends a trip signal to RPS channels A and C; NI-2/4 to channels B and D. Since each High Startup Rate channel would cause a trip on two RPS channels, the High Startup Rate trip is not tested when the reactor is critical.

The four Loss of Load Trip channels are all actuated by a single pressure switch monitoring turbine auto stop oil pressure which is not tested when the reactor is critical. Operating experience has shown that these components usually pass the Surveillance when performed at a Frequency of once per 7 days prior to each reactor startup.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.8

SR 3.3.1.8 is the performance of a CHANNEL CALIBRATION every 18 months.

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor (except neutron detectors). The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be consistent with the setpoint analysis.

The bistable setpoints must be found to trip within the Allowable Values specified in the LCO and left set consistent with the assumptions of the setpoint analysis. The Variable High Power Trip setpoint shall be verified to reset properly at several indicated power levels during (simulated) power increases and power decreases.

The as-found and as-left values must also be recorded and reviewed for consistency with the assumptions of the setpoint analysis.

As part of the CHANNEL CALIBRATION of the wide range Nuclear Instrumentation, automatic removal of the ZPM Bypass for the Low PCS Flow, TM/LP must be verified to assure that these trips are available when required.

The Frequency is based upon the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift.

This SR is modified by a Note which states that it is not necessary to calibrate neutron detectors because they are passive devices with minimal drift and because of the difficulty of simulating a meaningful signal. Slow changes in power range excore neutron detector sensitivity are compensated for by performing the daily calorimetric calibration (SR 3.3.1.3) and the monthly calibration using the incore detectors (SR 3.3.1.4). Sudden changes in detector performance would be noted during the required CHANNEL CHECKS (SR 3.3.1.1).

BASES

REFERENCES	1.	10 CFR 50, Appendix A, GDC 21
	2.	10 CFR 100
	3.	IEEE Standard 279-1971, April 5, 1972
	4.	FSAR, Chapter 14
	5.	CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

Table B 3.3.1-1 (page 1 of 1)
Instruments Affecting Multiple Specifications

Required Instrument Channels	**Affected Specifications**
Nuclear Instrumentation	
Source Range NI-1/3, Count Rate Indication @ C-150 Panel	3.3.8 (#1)
Source Range NI-1/3 & 2/4, Count Rate Signal	3.3.9 & 3.9.2
Wide Range NI-1/3 & 2/4, Flux Level 10^{-4} Bypass	3.3.1 (#3, 6, 7, 9, & 12)
Wide Range NI-1/3 & 2/4, Startup Rate	3.3.1 (#2)
Wide Range NI-1/3 & 2/4, Flux Level Indication	3.3.7 (#3) & 3.3.9
Power Range NI-5, 6, 7, & 8, Tq	3.2.1 & 3.2.3
Power Range NI-5, 6, 7, & 8, Q Power	3.3.1 (#1 & 9)
Power Range NI-5, 6, 7, & 8, ASI	3.3.1 (#9) & 3.2.1 & 3.2.4
Power Range NI-5, 6, 7, & 8, Loss of Load/High Startup Rate Bypass	3.3.1 (#2 & 10)
PCS T-Cold Instruments	
TT-0112CA, Temperature Signal (SPI ΔT Power for PDIL Alarm Circuit)	3.1.6
TT-0112CA & 0122CA, Temperature Signal (C-150)	3.3.8 (#6 & 7)
TT-0122CB, Temperature Signal (PIP ΔT Power for PDIL Alarm Circuit)	3.1.6
TT-0112CA & 0122CB, Temperature Signal (LTOP)	3.4.12.b.1
TT-0112CC & 0122CD (PTR-0112 & 0122) Temperature Indication	3.3.7 (#2)
TT-0112 & 0122 CC & CD, Temperature Signal (SMM)	3.3.7 (#5)
TT-0112 & 0122 CA, CB, CC, & CD, Temperature Signal (Q Power & TMM)	3.3.1 (#1 & 9) & 3.4.1.b
PCS T-Hot Instruments	
TT-0112HA, Temperature Signal (SPI ΔT Power for PDIL Alarm Circuit)	3.1.6
TT-0112HA & 0122HA, Temperature Signal (C-150)	3.3.8 (#4 & 5)
TT-0122HB, Temperature Signal (PIP ΔT Power for PDIL Alarm Circuit)	3.1.6
TT-0112 & 0122 HC & HD, Temperature Signal (SMM)	3.3.7 (#5)
TT-0112HC & 0122HD (PTR-0112 & 0122) Temperature Indication	3.3.7 (#1)
TT-0112 & 0122 HA, HB, HC, & HD, Temperature Signal (Q Power & TMM)	3.3.1 (#1 & 9)
Thermal Margin Monitors	
PY-0102A, B, C, & D	3.3.1 (#1 & 9)
Pressurizer Pressure Instruments	
PT-0102A, B, C, & D, Pressure Signal (RPS & SIS)	3.3.1 (#8 & 9) & 3.3.3 (#1.a & 7a)
PT-0104A & B, Pressure Signal (LTOP & SDC Interlock)	3.4.12.b.1 & 3.4.14
PT-0105A & B, Pressure Signal (WR Indication & LTOP)	3.3.7 (#5) & 3.4.12.b.1
PI-0110, Pressure Indication @ C-150 Panel	3.3.8 (#2)
SG Level Instruments	
LT-0751 & 0752 A, B, C, & D, Level Signal (RPS & AFAS)	3.3.1 (#4 & 5) & 3.3.3 (#4.a & 4.b)
LI-0757 & 0758 A & B, Wide Range Level Indication	3.3.7 (#11 & 12)
LI-0757C & 0758C, Wide Range Level Indication @ C-150 Panel	3.3.8 (#10 & 11)
SG Pressure Instruments	
PT-0751 & 0752 A, B, C, & D, Pressure Signal (RPS & SG Isolation)	3.3.1 (#6 & 7) & 3.3.3 (#2a, 2b, 7b, 7c)
PIC-0751 & 0752 C & D, Pressure Indication	3.3.7 (#13 & 14)
PI-0751E & 0752E, Pressure Indication @ C-150 Panel	3.3.8 (#8 & 9)
Containment Pressure Instruments	
PS-1801, 1802, 1803, & 1804, Switch Output (RPS)	3.3.1 (#11)
PS-1801, 1802A, 1803, & 1804A, Switch Output (ESF)	3.3.3 (#5.a)
PS-1801A, 1802, 1803A, & 1804, Switch Output (ESF)	3.3.3 (#5.b)

Note: The information provided in this table is intended for use as an aid to distinguish those instrument channels which provide more than one required function and to describe which specifications they affect. The information in this table should not be taken as inclusive for all instruments nor affected specifications.

B 3.3 INSTRUMENTATION

B 3.3.3 Engineered Safety Features (ESF) Instrumentation

BASES

BACKGROUND

The ESF Instrumentation initiates necessary safety systems, based upon the values of selected plant parameters, to protect against violating core design limits and the Primary Coolant System (PCS) pressure boundary and to mitigate accidents.

The ESF circuitry generates the signals listed below when the monitored variables reach levels that are indicative of conditions requiring protective action. The inputs to each ESF actuation signal are also listed.

1. Safety Injection Signal (SIS).
    a. Containment High Pressure (CHP)
    b. Pressurizer Low Pressure
2. Steam Generator Low Pressure (SGLP);
    a. Steam Generator A Low Pressure
    b. Steam Generator B Low Pressure
3. Recirculation Actuation Signal (RAS);
    a. Safety Injection Refueling Water Tank (SIRWT) Low Level
4. Auxiliary Feedwater Actuation Signal (AFAS);
    a. Steam Generator A Low Level
    b. Steam Generator B Low Level
5. Containment High Pressure Signal (CHP);
    a. Containment High Pressure - Left Train
    b. Containment High Pressure - Right Train

BASES

BACKGROUND (continued)

6. Containment High Radiation Signal (CHR);

   a. Containment High Radiation

7. Automatic Bypass Removal

   a. Pressurizer Pressure Low Bypass

   b. Steam Generator A Low Pressure Bypass

   c. Steam Generator B Low Pressure Bypass

In the above list of actuation signals, the CHP and RAS are derived from pressure and level switches, respectively.

Equipment actuated by each of the above signals is identified in the FSAR, Chapter 7. (Ref. 1).

The ESF circuitry, with the exception of RAS, employs two-out-of-four logic. Four independent measurement channels are provided for each function used to generate ESF actuation signals. When any two channels of the same function reach their setpoint, actuating relays are energized which, in turn, initiate the protective actions. Two separate and redundant trains of actuating relays, each powered from separate power supplies, are utilized. These separate relay trains operate redundant trains of ESF equipment.

RAS logic consists of output contacts of the relays actuated by the SIRWT level switches arranged in a "one-out-of-two taken twice" logic. The contacts are arranged so that at least one low level signal powered from each station battery is required to initiate RAS. Loss of a single battery, therefore, cannot either cause or prevent RAS initiation.

The ESF logic circuitry contains the capability to manually block the SIS actuation logic and the SGLP action logic during normal plant shutdowns to avoid undesired actuation of the associated equipment. In each case, when three of the four associated measurement channels are below the block setpoint, pressing a manual pushbutton will block the actuation signal for that train. If two of the four of the measurement channels increase above the block setpoint, the block will automatically be removed.

BASES

BACKGROUND (continued)

7. Automatic Bypass Removal (continued)

The sensor subsystems, including individual channel actuation bistables, is addressed in this LCO. The actuation logic subsystems, manual actuation, and downstream components used to actuate the individual ESF components are addressed in LCO 3.3.4.

Measurement Channels

Measurement channels, consisting of pressure switches, field transmitters, or process sensors and associated instrumentation, provide a measurable electronic signal based upon the physical characteristics of the parameter being measured.

Four identical measurement channels are provided for each parameter used in the generation of trip signals. These are designated Channels A through D. Measurement channels provide input to ESF bistables within the same ESF channel. In addition, some measurement channels may also be used as inputs to Reactor Protective System (RPS) bistables, and most provide indication in the control room.

When a channel monitoring a parameter indicates an abnormal condition, the bistable monitoring the parameter in that channel will trip. In the case of RAS and CHP, the sensors are latching auxiliary relays from level and pressure switches, respectively, which do not develop an analog input to separate bistables. Tripping two or more channels monitoring the same parameter will actuate both channels of Actuation Logic of the associated ESF equipment.

Three of the four measurement and bistable channels are necessary to meet the redundancy and testability of GDC 21 in Appendix A to 10 CFR 50 (Ref. 2). The fourth channel provides additional flexibility by allowing one channel to be removed from service for maintenance or testing while still maintaining a minimum two-out-of-three logic.

Since no single failure will prevent a protective system actuation and no protective channel feeds a control channel, this arrangement meets the requirements of IEEE Standard 279 -1971 (Ref. 3).

BASES

BACKGROUND (continued)

Measurement Channels (continued)

The ESF Actuation Functions are generated by comparing a single measurement to a fixed bistable setpoint. The ESF Actuation Functions utilize the following input instrumentation:

- Safety Injection Signal (SIS)

  The Safety Injection Signal can be generated by any of three inputs: Pressurizer Low Pressure, Containment High Pressure, or Manual Actuation. Manual Actuation is addressed by LCO 3.3.4; Containment High Pressure is discussed below. Four instruments (channels A through D), monitor Pressurizer Pressure to develop the SIS actuation. Each of these instrument channels has two individually adjustable ESF bistable trip devices, one for the bypass removal circuit (discussed below) and one for SIS. Each ESF bistable trip device actuates two auxiliary relays, one for each actuation train. The output contacts from these auxiliary relays form the logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Pressurizer Low Pressure SIS actuation bistable include the pressure measurement loop, the SIS actuation bistable, and the two auxiliary relays associated with that bistable. The bistables associated with automatic removal of the Pressurizer Low Pressure Bypass are discussed under Function 7.a, below.

- Low Steam Generator Pressure Signal (SGLP)

  There are two separate Low Steam Generator Pressure signals, one for each steam generator. For each steam generator, four instruments (channels A through D) monitor pressure to develop the SGLP actuation. Each of these instrument channels has two individually adjustable ESF bistable trip devices, one for the bypass removal circuit (discussed below) and one for SGLP. Each Steam SGLP bistable trip device actuates an auxiliary relay. The output contacts from these auxiliary relays form the SGLP logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Steam Generator Low Pressure Signal bistable include the pressure measurement loop, the SGLP actuation bistable, and the auxiliary relay associated with that bistable. The bistables associated with automatic removal of the SGLP Bypass are discussed under Function 7.a, below.

BASES

BACKGROUND (continued)

Measurement Channels (continued)

- Recirculation Actuation Signal (RAS)

  There are four Safety Injection Refueling Water (SIRW) Tank level instruments used to develop the RAS signal. Each of these instrument channels actuates two auxiliary relays, one for each actuation train. The output contacts from these auxiliary relays form the logic circuits addressed in LCO 3.3.4. The SIRW Tank Low Level instrument channels associated with each RAS actuation bistable include the level instrument and the two auxiliary relays associated with that instrument.

- Auxiliary Feedwater Actuation Signal (AFAS)

  There are two separate AFAS signals (AFAS channels A and B), each one actuated on low level in either steam generator. For each steam generator, four level instruments (channels A through D) monitor level to develop the AFAS actuation signals. The output contacts from the bistables on these level channels form the AFAS logic circuits addressed in LCO 3.3.4. The instrument channels associated with each Steam Generator Low Level Signal bistable include the level measurement loop and the Low Level AFAS bistable.

- Containment High Pressure Actuation (CHP)

  The Containment High Pressure signal is actuated by two sets of four pressure switches, one set for each train. The output contacts from these pressure switches form the CHP logic circuits addressed in LCO 3.3.4.

BASES

BACKGROUND (continued)

Measurement Channels (continued)

- Containment High Radiation Actuation (CHR)

  The CHR signal can be generated by either of two inputs: High Radiation or Manual Actuation. Manual Actuation is addressed by LCO 3.3.4. Four radiation monitor instruments (channels A through D), monitor containment area radiation level to develop the CHR signal. Each CHR monitor bistable device actuates one auxiliary relay which has contacts in each CHR logic train addressed in LCO 3.3.4. The instrument channels associated with each CHR actuation bistable include the radiation monitor itself and the associated auxiliary relay.

- Automatic Bypass Removal Functions

  Pressurizer Low Pressure and Steam Generator Low Pressure logic circuits have the capability to be blocked to avoid undesired actuation when pressure is intentionally lowered during plant shutdowns. In each case these bypasses are automatically removed when the measured pressure exceeds the bypass permissive setpoint. The measurement channels which provide the bypass removal signal are the same channels which provide the actuation signal. Each of these pressure measurement channels has two bistables, one for actuation and one for the bypass removal Function. The pressurizer pressure channels include an auxiliary relay actuated by the bypass removal bistable. The logic circuits for Automatic Bypass Removal Functions are addressed by LCO 3.3.4.

Several measurement instrument channels provide more than one required function. Those sensors shared for RPS and ESF functions are identified in Table B 3.3.1-1. That table provides a listing of those shared channels and the Specifications which they affect.

BASES

BACKGROUND (continued)

Bistable Trip Units

There are four channels of bistables, designated A through D, for each ESF Function, one for each measurement channel. The bistables for all required Functions, except CHP and RAS, receive an analog input from the measurement device, compare the analog input to trip setpoints, and provide contact output to the Actuation Logic. CHP and RAS are actuated by pressure switches and level switches respectively.

The Allowable Values are specified for each safety related ESF trip Function which is credited in the safety analysis. Nominal trip setpoints are specified in the plant procedures. The nominal setpoints are selected to ensure plant parameters do not exceed the Allowable Value if the instrument loop is performing as required. The methodology used to determine the nominal trip setpoints is also provided in plant documents. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified is more conservative than the analytical limit determined in the safety analysis in order to account for uncertainties appropriate to the trip Function. These uncertainties are addressed as described in plant documents. A channel is inoperable if its actual setpoint is not within its Allowable Value.

Setpoints in accordance with the Allowable Value will ensure that Safety Limits of Chapter 2.0, "SAFETY LIMITS (SLs)," are not violated during Anticipated Operational Occurrences (AOOs) and that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed. (As defined in 10 CFR 50, Appendix A, "Anticipated operational occurances mean those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power.")

ESF Instrument Channel Bypasses

The only ESF instrument channels with built-in bypass capability are the Low SG Level AFAS bistables. Those bypasses are effected by a key operated switch, similar to the RPS Trip Channel Bypasses. A bypassed Low SG Level channel AFAS bistable cannot perform its specified function and must be considered inoperable.

BASES

BACKGROUND (continued)

ESF Instrument Channel Bypasses (continued)

While there are no other built-in provisions for instrument channel bypasses in the ESF design (bypassing any other channel output requires opening a circuit link, lifting a lead, or using a jumper), this LCO includes requirements for OPERABILITY of the instrument channels and bistables which provide input to the Automatic Bypass Removal Logic channels required by LCO 3.3.4, "ESF Logic and Manual Initiation."

The Actuation Logic channels for Pressurizer Pressure and Steam Generator Low Pressure, however, have the ability to be manually bypassed when the associated pressure is below the range where automatic protection is required. These actuation logic channel bypasses may be manually initiated when three-out-of-four bypass permissive bistables indicate below their setpoint. When two-out-of-four of these bistables are above their bypass permissive setpoint, the actuation logic channel bypass is automatically removed. The bypass permissive bistables use the same four measurement channels as the blocked ESF function for their inputs.

APPLICABLE SAFETY ANALYSES

Each of the analyzed accidents can be detected by one or more ESF Functions. One of the ESF Functions is the primary actuation signal for that accident. An ESF Function may be the primary actuation signal for more than one type of accident. An ESF Function may also be a secondary, or backup, actuation signal for one or more other accidents. Functions not specifically credited in the accident analysis, serve as backups and are part of the NRC approved licensing basis for the plant.

BASES

APPLICABLE SAFETY ANALYSES (continued)

ESF protective Functions are as follows.

1. Safety Injection Signal (SIS)

The SIS ensures acceptable consequences during Loss of Coolant Accident (LOCA) events, including steam generator tube rupture, and Main Steam Line Breaks (MSLBs) or Feedwater Line Breaks (FWLBs) (inside containment). To provide the required protection, SIS is actuated by a CHP signal, or by two-out-of-four Pressurizer Low Pressure channels decreasing below the setpoint. SIS initiates the following actions:

a. Start HPSI & LPSI pumps;

b. Start component cooling water and service water pumps;

c. Initiate service water valve operations;

d. Initiate component cooling water valve operations;

e. Start containment cooling fans (when coincident with a loss of offsite power);

f. Enable Containment Spray Pump Start on CHP; and

g. Initiate Safety Injection Valve operations.

Each SIS logic train is also actuated by a contact pair on one of the CHP initiation relays for the associated CHP train.

2. Steam Generator Low Pressure Signal (SGLP)

The SGLP ensures acceptable consequences during an MSLB or FWLB by isolating the steam generator if it indicates a low steam generator pressure. The SGLP concurrent with or following a reactor trip, minimizes the rate of heat extraction and subsequent cooldown of the PCS during these events.

BASES

APPLICABLE SAFETY ANALYSES (continued)

2. Steam Generator Low Pressure Signal (SGLP) (continued)

One SGLP circuit is provided for each SG. Each SGLP circuit is actuated by two-out-of-four pressure channels on the associated SG reaching their setpoint. SGLP initiates the following actions:

a. Close the associated Feedwater Regulating valve and its bypass; and

b. Close both Main Steam Isolation Valves.

3. Recirculation Actuation Signal

At the end of the injection phase of a LOCA, the SIRWT will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. Switchover from SIRWT to the containment sump must occur before the SIRWT empties to prevent damage to the ECCS pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support pump suction.

Furthermore, early switchover must not occur to ensure sufficient borated water is injected from the SIRWT to ensure the reactor remains shut down in the recirculation mode. An SIRWT Low Level signal initiates the RAS.

RAS initiates the following actions:

a. Trip LPSI pumps (this trip can be manually bypassed);

b. Switch HPSI and containment spray pump suction from SIRWT to Containment Sump by opening sump CVs and closing SIRWT CVs;

c. Adjust cooling water to component cooling heat exchangers;

d. Open HPSI subcooling valve CV-3071 if the associated HPSI pump is operating;

e. After containment sump valve CV-3030 is opened, open HPSI subcooling valve CV-3070 if the associated HPSI pump is operating;

f. Close containment spray valve CV-3001 if containment sump valve CV-3030 does not open.

BASES

APPLICABLE SAFETY ANALYSES (continued)

3 Recirculation Actuation Signal (continued)

The RAS signal is actuated by separate sensors from those which provide tank level indication. The allowable range of 21" to 27" above the tank floor corresponds to 1.1% to 3.3% indicated level. Typically the actual setting is near the midpoint of the allowable range.

4 Auxiliary Feedwater Actuation Signal

An AFAS initiates feedwater flow to both steam generators if a low level is indicated in either steam generator.

The AFAS maintains a steam generator heat sink during the following events:

- MSLB;
- FWLB;
- LOCA; and
- Loss of feedwater.

5. Containment High Pressure Signal (CHP)

The CHP signal closes all containment isolation valves not required for ESF operation and starts containment spray (if SIS enabled), ensuring acceptable consequences during LOCAs, control rod ejection events, MSLBs, or FWLBs (inside containment).

CHP is actuated by two-out-of-four pressure switches for the associated train reaching their setpoints. CHP initiates the following actions:

a. Containment Spray;

b. Safety Injection Signal;

c. Main Feedwater Isolation;

BASES

APPLICABLE SAFETY ANALYSIS (continued)

5. Containment High Pressure Signal (CHP) (continued)

   d. Main Steam Line Isolation;

   e. Control Room HVAC Emergency Mode; and

   f. Containment Isolation Valve Closure.

6. Containment High Radiation Signal (CHR)

   CHR is actuated by two-out-of-four radiation monitors exceeding their setpoints. CHR initiates the following actions to ensure acceptable consequences following a LOCA or control rod ejection event:

   a. Control Room HVAC Emergency Mode;

   b. Containment Isolation Valve Closure; and

   c. Block automatic starting of ECCS pump room sump pumps.

   During refueling operations, separate switch-selectable radiation monitors initiate CHR, as addressed by LCO 3.3.6.

7. Automatic Bypass Removal Functions

   The logic circuitry provides automatic removal of the Pressurizer Pressure Low and Steam Generator Pressure Low actuation signal bypasses. There are no assumptions in the safety analyses which assume operation of these automatic bypass removal circuits, and no analyzed events result in conditions where the automatic removal would be required to mitigate the event. The automatic removal circuits are required to assure that logic circuit bypasses will not be overlooked during a plant startup.

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

BASES

LCO

The LCO requires all channel components necessary to provide an ESF actuation to be OPERABLE.

The Bases for the LCO on ESF Functions are addressed below.

1. Safety Injection Signal (SIS)

This LCO requires four channels of SIS Pressurizer Low Pressure to be OPERABLE in MODES 1, 2, and 3.

The setpoint was chosen so as to be low enough to avoid actuation during plant operating transients, but to be high enough to be quickly actuated by a LOCA or MSLB. The settings include an uncertainty allowance which is consistent with the settings assumed in the MSLB analysis (which bounds the settings assumed in the LOCA analysis).

2. Steam Generator Low Pressure Signal (SGLP)

This LCO requires four channels of Steam Generator Low Pressure Instrumentation for each SG to be OPERABLE in MODES 1, 2, and 3. However, as indicated in Table 3.3.3-1, Note (a), the SGLP Function is not required to be OPERABLE in MODES 2 or 3 if all Main Steam Isolation Valves (MSIVs) are closed and deactivated and all Main Feedwater Regulating Valves (MFRVs) and MFRV bypass valves are either closed and deactivated or isolated by closed manual valves.

The setpoint was chosen to be low enough to avoid actuation during plant operation, but be close enough to full power operating pressure to be actuated quickly in the event of a MSLB. The setting includes an uncertainty allowance which is consistent with the setting used in the Reference 4 analysis.

Each SGLP logic is made up of output contacts from four pressure bistables from the associated SG. When the logic circuit is satisfied, two relays are energized to actuate steam and feedwater line isolation.

BASES

LCO (continued)

2. Steam Generator Low Pressure Signal (SGLP) (continued)

This LCO applies to failures in the four sensor subsystems, including sensors, bistables, and associated equipment. Failures in the actuation subsystems are considered Actuation Logic failures and are addressed in LCO 3.3.4.

3. Recirculation Actuation Signal (RAS)

This LCO requires four channels of SIRWT Low Level to be OPERABLE in MODES 1, 2, and 3.

The setpoint was chosen to provide adequate water in the containment sump for HPSI pump net positive suction head following an accident, but prevent the pumps from running dry during the switchover.

The upper limit on the Allowable Value for this trip is set low enough to ensure RAS does not initiate before sufficient water is transferred to the containment sump. Premature recirculation could impair the reactivity control Function of safety injection by limiting the amount of boron injection. Premature recirculation could also damage or disable the recirculation system if recirculation begins before the sump has enough water.

The lower limit on the SIRWT Low Level trip Allowable Value is high enough to transfer suction to the containment sump prior to emptying the SIRWT.

4. Auxiliary Feedwater Actuation Signal (AFAS)

The AFAS logic actuates AFW to each SG on a SG Low Level in either SG.

The Allowable Value was chosen to assure that AFW flow would be initiated while the SG could still act as a heat sink and steam source, and to assure that a reactor trip would not occur on low level without the actuation of AFW.

BASES

LCO (continued)

4. Auxiliary Feedwater Actuation Signal (AFAS) (continued)

This LCO requires four channels for each steam generator of Steam Generator Low Level to be OPERABLE in MODES 1, 2, and 3.

5. Containment High Pressure Signal (CHP)

This LCO requires four channels of CHP to be OPERABLE for each of the associated ESF trains (left and right) in MODES 1, 2, 3 and 4.

The setpoint was chosen so as to be high enough to avoid actuation by containment temperature or atmospheric pressure changes, but low enough to be quickly actuated by a LOCA or a MSLB in the containment.

6. Containment High Radiation Signal (CHR)

This LCO requires four channels of CHR to be OPERABLE in MODES 1, 2, 3, and 4.

The setpoint is based on the maximum primary coolant leakage to the containment atmosphere allowed by LCO 3.4.13 and the maximum activity allowed by LCO 3.4.16. N^{16} concentration reaches equilibrium in containment atmosphere due to its short half-life, but other activity was assumed to build up. At the end of a 24 hour leakage period the dose rate is approximately 20 R/h as seen by the area monitors. A large leak could cause the area dose rate to quickly exceed the 20 R/h setting and initiate CHR.

7. Automatic Bypass Removal

The automatic bypass removal logic removes the bypasses which are used during plant shutdown periods, for Pressurizer Low Pressure and Steam Generator Low Pressure actuation signals.

The setpoints were chosen to be above the setpoint for the associated actuation signal, but well below the normal operating pressures.

BASES

LCO (continued)

7. Automatic Bypass Removal (continued)

This LCO requires four channels of Pressurizer Low Pressure bypass removal and four channels for each steam generator of Steam Generator Low Pressure bypass removal, to be OPERABLE in MODES 1, 2, and 3.

APPLICABILITY

All ESF Functions are required to be OPERABLE in MODES 1, 2, and 3. In addition, Containment High Pressure and Containment High Radiation are required to be operable in MODE 4.

In MODES 1, 2, and 3 there is sufficient energy in the primary and secondary systems to warrant automatic ESF System responses to:

- Close the main steam isolation valves to preclude a positive reactivity addition and containment overpressure;
- Actuate AFW to preclude the loss of the steam generators as a heat sink (in the event the normal feedwater system is not available);
- Actuate ESF systems to prevent or limit the release of fission product radioactivity to the environment by isolating containment and limiting the containment pressure from exceeding the containment design pressure during a design basis LOCA or MSLB; and
- Actuate ESF systems to ensure sufficient borated inventory to permit adequate core cooling and reactivity control during a design basis LOCA or MSLB accident.

The CHP and CHR Functions are required to be OPERABLE in MODE 4 to limit leakage of radioactive material from containment and limit operator exposure during and following a DBA.

The SGLP Function is not required to be OPERABLE in MODES 2 and 3, if all MSIVs are closed and deactivated and all MFRVs and MFRV bypass valves are either closed and deactivated or isolated by closed manual valves, since the SGLP Function is not required to perform any safety functions under these conditions.

BASES

APPLICABILITY (continued)

In lower MODES, automatic actuation of ESF Functions is not required, because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating the ESF components.

LCO 3.3.6 addresses automatic Refueling CHR isolation during CORE ALTERATIONS or during movement of irradiated fuel.

In MODES 5 and 6, ESFAS initiated systems are either reconfigured or disabled for shutdown cooling operation. Accidents in these MODES are slow to develop and would be mitigated by manual operation of individual components.

ACTIONS

The most common causes of channel inoperability are outright failure of loop components or drift of those loop components which is sufficient to exceed the tolerance provided in the plant setpoint analysis. Loop component failures are typically identified by the actuation of alarms due to the channel failing to the "safe" condition, during CHANNEL CHECKS (when the instrument is compared to the redundant channels), or during the CHANNEL FUNCTIONAL TEST (when an automatic component might not respond properly). Typically, the drift of the loop components is found to be small and results in a delay of actuation rather than a total loss of function. Excessive loop component drift would, most likely, be identified during a CHANNEL CHECK (when the instrument is compared to the redundant channels) or during a CHANNEL CALIBRATION (when instrument loop components are checked against reference standards).

Typically, the drift is small and results in a delay of actuation rather than a total loss of function. Determination of setpoint drift is generally made during the performance of a CHANNEL FUNCTIONAL TEST when the process instrument is set up for adjustment to bring it to within specification. If the actual trip setpoint is not within the Allowable Value in Table 3.3.3-1, the channel is inoperable and the appropriate Condition(s) are entered.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value in Table 3.3.3-1, or the sensor, instrument loop, signal processing electronics, or ESF bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the plant must enter the Condition statement for the particular protection Function affected.

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip Function exceeds those specified in any related Condition associated with the same trip Function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A Note has been added to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function in Table 3.3.3-1. Completion Times for the inoperable channel of a Function will be tracked separately.

A.1

Condition A applies to the failure of a single bistable or associated instrumentation channel of one or more input parameters in each ESF Function except the RAS Function. Since the bistable and associated instrument channel combine to perform the actuation function, the Condition is also appropriate if both the bistable and associated instrument channel are inoperable.

ESF coincidence logic is normally two-out-of-four. If one ESF channel is inoperable, startup or power operation is allowed to continue as long as action is taken to restore the design level of redundancy.

If one ESF channel is inoperable, startup or power operation is allowed to continue, providing the inoperable channel actuation bistable is placed in trip within 7 days. The provision of four trip channels allows one channel to be inoperable in a non-trip condition up to the 7 day Completion Time allotted to place the channel in trip. Operating with one failed channel in a non-trip condition during operations, places the ESF Actuation Logic in a two-out-of-three coincidence logic.

If the failed channel cannot be restored to OPERABLE status in 7 days, the associated bistable is placed in a tripped condition. This places the function in a one-out-of-three configuration.

BASES

ACTIONS (continued)

A.1 (continued)

In this configuration, common cause failure of the dependent channel cannot prevent ESF actuation. The 7 day Completion Time is based upon operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

Condition A is modified by a Note which indicates it is not applicable to the SIRWT Low Level Function.

B.1 and B.2

Condition B applies to the failure of two channels in any of the ESF Functions except the RAS Function.

With two inoperable channels, one channel actuation device must be placed in trip within the 8 hour Completion Time. Eight hours is allowed for this action since it must be accomplished by a circuit modification, or by removing power from a circuit component. With one channel of protective instrumentation inoperable, the ESF Actuation Logic Function is in two-out-of-three logic, but with another channel inoperable the ESF may be operating with a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the ESF in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, ESF actuation will occur.

One of the failed channels must be restored to OPERABLE status within 7 days, and the provisions of Condition A still applied to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action B.2 must be placed in trip if more than 7 days has elapsed since the channel's initial failure.

BASES

ACTIONS (continued)

B.1 and B.2 (continued)

Condition B is modified by a Note which indicates that it is not applicable to the SIRWT Low Level Function.

C.1 and C.2

Condition C applies to one RAS SIRWT Low Level channel inoperable. The SIRWT low level circuitry is arranged in a "1-out-of-2 taken twice" logic rather than the more frequently used 2-out-of-4 logic. Therefore, Required Action C.1 differs from other ESF functions. With a bypassed SIRWT low level channel, an additional failure might disable automatic RAS, but would not initiate a premature RAS. With a tripped channel, an additional failure could cause a premature RAS, but would not disable the automatic RAS.

Since considerable time is available after initiation of SIS until RAS must be initiated, and since a premature RAS could damage the ESF pumps, it is preferable to bypass an inoperable channel and risk loss of automatic RAS than to trip a channel and risk a premature RAS.

The Completion Time of 8 hours allowed is reasonable because the Required Action involves a circuit modification.

Required Action C.2 requires that the inoperable channel be restored to OPERABLE status within 7 days. The Completion Time is reasonable based upon operating experience, which has demonstrated that a random failure of a second channel occurring during the 7 day period is a low probability event.

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Actions and associated Completion Times of Condition A, B, or C are not met for Functions 1, 2, 3, 4, or 7, 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 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, or C are not met for Functions 5 or 6, 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

The SRs for any particular ESF Function are found in the SRs column of Table 3.3.3-1 for that Function. Most functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

SR 3.3.3.1

A CHANNEL CHECK is performed once every 12 hours on each ESF input channel which is provided with an indicator to provide a qualitative assurance that the channel is working properly and that its readings are within limits. A CHANNEL CHECK is not performed on the CHP and SIRWT Low Level channels because they have no associated control room indicator.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.1 (continued)

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between 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 the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when Surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Offscale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

A CHANNEL FUNCTIONAL TEST is performed every 92 days to ensure the entire channel will perform its intended function when needed. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

This test is required to be performed each 92 days on ESF input channels provided with on-line testing capability. It is not required for the SIRWT Low Level channels since they have no built in test capability. The CHANNEL FUNCTIONAL TEST for SIRWT Low Level channels is performed each 18 months as part of the required CHANNEL CALIBRATION.

The CHANNEL FUNCTIONAL TEST tests the individual channels using an analog test input to each bistable.

Any setpoint adjustment shall be consistent with the assumptions of the current setpoint analysis.

The Frequency of 92 days is based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Reference 5).

SR 3.3.3.3

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive surveillances. CHANNEL CALIBRATIONS must be performed consistent with the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.3 (continued)

The as found and as left values must also be recorded and reviewed for consistency with the assumptions of the extension analysis. The requirements for this review are outlined in Reference 5.

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

REFERENCES

1. FSAR, Chapter 7
2. 10 CFR 50, Appendix A
3. IEEE Standard 279-1971
4. FSAR, Chapter 14
5. CEN-327, June 2, 1986, including Supplement 1, March 3, 1989

B 3.3 INSTRUMENTATION

B 3.3.7 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the Post Accident Monitoring (PAM) instrumentation is to display plant 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, that are required for safety systems to accomplish their safety Functions for Design Basis Events.

The OPERABILITY of the PAM instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident.

The availability of PAM instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. The required instruments are identified in FSAR Appendix 7C (Ref. 1) and address the recommendations of Regulatory Guide 1.97 (Ref. 2), as required by Supplement 1 to NUREG-0737, "TMI Action Items" (Ref. 3).

Type A variables are included in this LCO because they provide the primary information required to permit the control room operator to take specific manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions for Design Basis Accidents (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;
- Provide information to the operators that will enable them to determine the potential for causing a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public and for an estimate of the magnitude of any impending threat.

BASES

BACKGROUND (continued)

These key variables are identified in the plant specific Regulatory Guide 1.97 analyses (Ref. 1). This analysis identified the plant specific Type A and Category 1 variables and provided justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.7-1 are discussed in the LCO Bases.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the OPERABILITY of Regulatory Guide 1.97 Type A 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; and
- Take the specified, preplanned, manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions.

The PAM instrumentation also ensures OPERABILITY of Category I, non-Type A variables. This ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public as well as to obtain an estimate of the magnitude of any impending threat.

Category I, non-Type A PAM instruments are retained in the Specification because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I variables are important in reducing public risk.

PAM instrumentation that satisfies the definition of Type A in Regulatory Guide 1.97 meets Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

LCO 3.3.7 requires at least two OPERABLE channels for all Functions except Containment Isolation Valve Position Indication. This is to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following that accident.

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

For Containment Isolation Valve Position indication, the important information is the status of the containment penetrations. The LCO requires one position indication channel for each containment isolation valve listed in FSAR Appendix 7C (Ref. 1).

Listed below are discussions of the specified instrument Functions listed in Table 3.3.7-1. Component identifiers of the sensors, indicators, power supplies, displays, and recorders in each instrument loop are found in Reference 1.

1, 2. <u>Primary Coolant System (PCS) Hot and Cold Leg Temperature (wide range)</u>

PCS wide range Hot and Cold Leg Temperatures are Type B, Category 1 variables provided for verification of core cooling and long term surveillance.

Reactor outlet temperature inputs to the PAM are provided by two wide range resistance elements and associated transmitters (one in each loop). The channels provide indication over a range of 50°F to 700°F.

3. <u>Wide Range Neutron Flux</u>

Wide Range Neutron Flux indication is a Type B, Category 1 variable, and is provided to verify reactor shutdown.

4. <u>Containment Floor Water Level (wide range)</u>

Wide range Containment Floor Water Level is a Type B, Category 1 variable, and is provided for verification and long-term surveillance of PCS integrity.

BASES

LCO (continued)

5. Subcooled Margin Monitor

The Subcooled Margin Monitor (SMM) is a Type A, Category 1 variable used to identify conditions, which require tripping of the primary coolant pumps and throttling of safety injection flows. Each SMM channel uses a number of PCS pressure and temperature inputs to determine the degree of PCS subcooling or superheat.

6. Pressurizer Level (Wide Range)

Pressurizer Level is a Type A, Category 1 variable, and is used to determine whether to terminate Safety Injection (SI), if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the plant conditions necessary to establish natural circulation in the PCS and to verify that the plant is maintained in a safe shutdown condition.

7. (Deleted)

8. Condensate Storage Tank (CST) Level

CST Level is a Type D, Category 1 variable, and is provided to ensure water supply for AFW. The CST provides the safety grade water supply for the AFW System. Inventory is monitored by a 0 to 100% level indication. CST Level is displayed on a control room indicator. In addition, a control room annunciator alarms on low level.

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.

BASES

LCO (continued)

9. Primary Coolant System Pressure (wide range)

PCS wide range pressure is a Type A, Category 1 variable provided for verification of core cooling and PCS integrity long-term surveillance.

Wide range PCS loop pressure is measured by pressure transmitters with a span of 0 psia to 3000 psig. Redundant monitoring capability is provided by two channels of instrumentation. Control room indications are provided on C12 and C02.

10. Containment Pressure (wide range)

Wide range Containment Pressure is a Type C, Category 1 variable, and is provided for verification of PCS and containment OPERABILITY. It is also an input to decisions for initiating containment spray.

11, 12. Steam Generator Water Level (wide range)

Wide range Steam Generator Water Level is a Type A, Category 1 variable, and is provided to monitor operation of decay heat removal via the steam generators. The steam generator level instrumentation covers a span extending from the tube sheet to the steam separators, with an indicated range of -140% to +150%. Redundant monitoring capability is provided by two channels of instrumentation for each SG.

Operator action for maintenance of heat removal is based on the control room indication of Steam Generator Water Level. The indication is used during a SG tube rupture to determine which SG has the ruptured tube. It is also used to determine when to initiate once through cooling on low water level.

13, 14. SG Pressure

Steam Generator Pressure is a Type A, Category 1 variable used in accident identification, including Loss of Coolant, and Steam Line Break. Redundant monitoring capability is provided by two channels of instrumentation for each SG.

BASES

LCO (continued)

15. Containment Isolation Valve Position

Containment Isolation Valve (CIV) Position is a Type B, Category 1 variable, and is provided for verification of containment OPERABILITY.

CIV position is provided for verification of containment integrity. In the case of CIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each CIV listed in FSAR Appendix 7C (Ref. 1). This is sufficient to redundantly verify the isolation status of each associated penetration via indicated status of the CIVs, and by knowledge of a passive (check) valve or a closed system boundary.

If a penetration flow path is isolated, position indication for the CIV(s) in the associated penetration flow path is not needed to determine status. Therefore, as indicated in Note (a) the position indication for valves in an isolated penetration flow path is not required to be OPERABLE.

16, 17, 18, 19. Core Exit Temperature

Core Exit Temperature is a Type C, Category 1 variable, and is provided for verification and long term surveillance of core cooling.

Each Required Core Exit Thermocouple (CET) channel consists of a single environmentally qualified thermocouple.

The design of the Incore Instrumentation System includes a Type K (chromel alumel) thermocouple within each of the incore instrument detector assemblies.

The junction of each thermocouple is located above the core exit, inside the incore detector assembly guide tube, that supports and shields the incore instrument detector assembly string from flow forces in the outlet plenum region. These core exit thermocouples monitor the temperature of the reactor coolant as it exits the fuel assemblies.

The core exit thermocouples have a usable temperature range from 32°F to 2300°F, although accuracy is reduced at temperatures above 1800°F.

BASES

LCO (continued)

20. Reactor Vessel Water Level

Reactor Vessel Water Level is monitored by the Reactor Vessel Level Monitoring System (RVLMS) and is a Type B, Category 1 variable provided for verification and long-term surveillance of core cooling.

The RVLMS provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory. The collapsed level is obtained over the same temperature and pressure range as the saturation measurements, thereby encompassing all operating and accident conditions where it must function. Also, it functions during the recovery interval. Therefore, it is designed to survive the high steam temperature that may occur during the preceding core recovery interval.

The level range extends from the top of the vessel down to the top of the fuel alignment plate. A total of eight Heated Junction Thermocouple (HJTC) pairs are employed in each of the two RVLMS channels. Each pair consists of a heated junction TC and an unheated junction TC. The differential temperature at each HJTC pair provides discrete indication of uncovery at the HJTC pair location. This indication is displayed using LEDs in the control room. This provides the operator with adequate indication to track the progression of the accident and to detect the consequences of its mitigating actions or the functionality of automatic equipment.

A RVLMS channel consists of eight sensors in a probe. A channel is OPERABLE if four or more sensors, two or more of the upper four and two or more of the lower four, are OPERABLE.

21. Containment Area Radiation (high range)

High range Containment Area Radiation is a Type E, Category 1 variable, and is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

BASES

APPLICABILITY	The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, plant conditions are such that the likelihood of an event occurring that would require PAM instrumentation is low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS, even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to monitor an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 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 Table 3.3.7-1. 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.

<u>A.1</u>

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

BASES

ACTIONS (continued)

B.1

This Required Action specifies initiation of actions in accordance with Specification 5.6.6, which requires a written report to be submitted to the Nuclear Regulatory Commission. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative Required Actions. This Required Action is appropriate in lieu of a shutdown requirement, given the likelihood of plant conditions that would require information provided by this instrumentation. Also, alternative Required Actions are identified before a loss of functional capability condition occurs.

C.1

When one or more Functions have two required channels inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrumentation operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Condition D is currently not used.

BASES

ACTIONS (continued)

E.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.7-1. The applicable Condition referenced in the Table is Function dependent. Each time Required Action C.1 is not met, and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Condition C is not met, and Table 3.3.7-1 directs entry into Condition F, the plant must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 30 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed and tested. These alternate means may be temporarily installed 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 plant, but rather to follow the directions of Specification 5.6.6. 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.

BASES

SURVEILLANCE REQUIREMENTS

A Note at the beginning of the Surveillance Requirements specifies that the following SRs apply to each PAM instrumentation Function in Table 3.3.7-1.

SR 3.3.7.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Off scale low current loop channels are verified to be reading at the bottom of the range and not failed downscale.

As indicated in the SR, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31-day interval is a rare event. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel during normal operational use of the displays associated with this LCO's required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2

A CHANNEL CALIBRATION is performed every 18 months or approximately every refueling. CHANNEL CALIBRATION is typically a complete check of the instrument channel including the sensor. Therefore, this SR is modified by a Note, which states that it is not necessary to calibrate neutron detectors because of the difficulty of simulating a meaningful signal. Wide range and source range nuclear instrument channels are not calibrated to indicate the actual power level or the flux in the detector location. The circuitry is adjusted so that wide range and source range readings may be used to determine the approximate reactor flux level for comparative purposes. The Surveillance verifies the channel responds to the measured parameter within the necessary range and accuracy.

For the core exit thermocouples, a CHANNEL CALIBRATION is performed by substituting a known voltage for the thermocouple.

The Frequency is based upon operating experience and consistency with the typical industry refueling cycle and is justified by an 18 month calibration interval for the determination of the magnitude of equipment drift.

REFERENCES

1. FSAR, Appendix 7C, "Regulatory Guide 1.97 Instrumentation"
2. Regulatory Guide 1.97
3. NUREG-0737, Supplement 1

B 3.3 INSTRUMENTATION

B 3.3.8 Alternate Shutdown System

BASES

BACKGROUND

The Alternate Shutdown System provides the control room operator with sufficient instrumentation and controls to maintain the plant 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 plant in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator safety valves or the steam generator atmospheric dump valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Primary Coolant System (PCS) from outside the control room allow extended operation in MODE 3.

The Auxiliary Hot Shutdown Panels (C-150/C-150A) are located in the southwest electrical penetration room. These panels are comprised of two enclosures, the main enclosure C-150 and an auxiliary enclosure C-150A. The description below combines these two enclosures into one entity "Panel C-150."

Panel C-150 provides control of the AFW flow control valves and AFW turbine steam supply Valve. Indication of AFW flow, Steam Generator water level, pressurizer pressure, and pressurizer level are provided. See FSAR Section 7.4 (Ref. 1) for operation via Panel C-150.

The instrumentation and equipment controls that are required are listed in Table 3.3.8-1.

Switches, which transfer control or instrument functions from the control room to the C-150 panel, alarm in the control room when the C-150 panel is selected.

APPLICABLE SAFETY ANALYSES

The Alternate Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to maintain the plant in a safe condition in MODE 3.

The criteria governing the design and the specific system requirements of the Alternate Shutdown System are located in 10 CFR 50, Appendix A, GDC 19, and Appendix R (Ref. 2).

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Alternate Shutdown System has been identified as an important contributor to the reduction of plant risk to accidents and, therefore, satisfies the requirements of Criterion 4 of 10 CFR 50.36(c)(2).

LCO

The Alternate Shutdown System LCO provides the requirements for the OPERABILITY of one channel of the instrumentation and controls necessary to maintain the plant in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Table 3.3.8-1 in the accompanying LCO.

Equipment controls that are required by the alternative dedicated method of maintaining MODE 3 are as follows:

1. AFW flow control valves (CV-0727 and CV-0749); and
2. Turbine-driven AFW pump.

Instrumentation systems displayed on the Auxiliary Hot Shutdown Control Panel are:

1. Source range flux monitor;
2. AFW flow (HIC-0727 and HIC-0749C);
3. Pressurizer pressure;
4. Pressurizer level;
5. SG level and pressure;
6. Primary coolant temperatures (hot and cold legs);
7. Turbine-driven AFW pump low-suction pressure warning light; and
8. SIRW tank level.

A Function of an Alternate Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown Functions are OPERABLE.

BASES

LCO (continued)

The Alternate Shutdown System instrumentation and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instrument and control circuits will be OPERABLE if plant conditions require that the Alternate Shutdown System be placed in operation.

Table 3.3.8-1 Indication Channel 1, Source Range Nuclear Instrumentation, uses the same detector and preamplifier as the control room channel. Optical isolation is provided between the control room and AHSDP (Alternate Hot Shut Down Panel) portions of the circuit. When the control switches are changed to the "AHSDP" position, the detector and preamplifier is isolated from its normal power supply and connected into the AHSDP power supply.

Table 3.3.8-1 Indication Channels 2 and 12 are provided with their own pressure and level transmitter. The associated circuitry is energized when the AHSDP is energized.

The other Table 3.3.8-1 Indication Channels in Table 3.3.8-1 use a transmitter which also serves normal control room instrumentation. When the control switches are changed to the "AHSDP" (Alternate Hot Shut Down Panel) position, the transmitter is isolated from its normal power supply and circuitry, and connected into the C-150 or C-150A panel circuit; control for AFW flow control valves CV-0727 and CV-0749 is also transferred to C-150. The transfer switches are alarmed in the control room.

APPLICABILITY

The Alternate Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the plant can be maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the plant is already subcritical and in the condition of reduced PCS energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control become unavailable.

BASES

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 in Table 3.3.8-1. The Completion Time of the inoperable channel of a Function will be tracked separately for each Function, starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where the required channels of the Remote Shutdown System are inoperable. This includes any Function listed in Table 3.3.8-1 as well as the control and transfer switches.

Required Action A.1 is to restore the channel to OPERABLE status within 30 days. This allows time to complete repairs on the failed channel. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A 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 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

This SR applies to the startup range neutron flux monitoring channel. The CHANNEL FUNCTIONAL TEST consists of verifying proper response of the channel to the internal test signals, and verification that a detectable signal is available from the detector. After lengthy shutdown periods flux may be below the range of the channel indication. Signal verification with test equipment is acceptable.

The CHANNEL FUNCTIONAL TEST of the startup range neutron flux monitoring channel is performed once within 7 days prior to reactor startup. The Frequency is based on plant operating experience that demonstrates channel failure is rare.

SR 3.3.8.2

SR 3.3.8.2 verifies that each required Alternate Shutdown System transfer switch and control circuit performs its intended function. This verification is performed from AHSDPs C-150 and C-150A and locally, as appropriate. Operation of the equipment from the AHSDPs C-150 and C-150A 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 plant can be maintained in MODE 3 from the auxiliary shutdown panel and the local control stations.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience demonstrates that Alternate Shutdown System control channels seldom fail to pass the Surveillance when performed at a Frequency of once every 18 months.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.3

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

Performance of a CHANNEL CALIBRATION every 18 months on Functions 1 through 15 ensures that the channels are operating accurately and within specified tolerances. This verification is performed from the AHSDPs and locally, as appropriate. A test of the AFW pump suction pressure alarm (Function 15) is included as part of its CHANNEL CALIBRATION. This will ensure that if the control room becomes inaccessible, the plant can be maintained in MODE 3 from the AHSDPs and local control stations.

The 18 month Frequency is based upon the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience demonstrates that Alternate Shutdown System instrumentation channels seldom fail to pass the Surveillance when performed at a Frequency of once every 18 months. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. Note 1 states that the SR is not required for Functions 16, 17, and 18; Note 2 states that it is not necessary to calibrate neutron detectors because of the difficulty of simulating a meaningful signal. Wide range and source range nuclear instrument channels are not calibrated to indicate the actual power level or the flux in the detector location. The circuitry is adjusted so that wide range and source range readings may be used to determine the approximate reactor flux level for comparative purposes.

REFERENCES

1. FSAR, Section 7.4, "Other Safety Related Protection, Control, and Display Systems"

2. 10 CFR 50, Appendix A, GDC 19 and Appendix R.

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.3 PCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the PCS 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 PCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

Figures 3.4.3-1 and 3.4.3-2 contain P/T limit curves for heatup, cooldown, and Inservice Leak and Hydrostatic (ISLH) testing, and data for the maximum rate of change of primary coolant temperature. A discussion of the methodology for the development of the P/T curves is provided in Reference 1 and Reference 7.

Each P/T limit curve defines an acceptable region for normal operation. The P/T limit curves include an allowance to account for the fact that pressure is measured in the pressurizer rather than at the vessel beltline and to account for primary coolant pump discharge pressure. The use of the curves provides operational limits 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 Primary Coolant Pressure Boundary (PCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply to the vessel.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for material fracture toughness requirements of the PCPB 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 ASME Code, Section III, Appendix G (Ref. 3).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 3.

BASES

BACKGROUND (continued)

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal may alter the location of the tensile stress between the outer and inner walls.

The minimum temperature at which the reactor can be made critical, as required by Reference 2, shall be at least 40°F above the heatup curve or the cooldown curve and not less than the minimum permissible temperature for the ISLH testing. However, the criticality limit is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "PCS Minimum Temperature for Criticality," and LCO 3.1.7, "Special Test Exceptions (STE)."

The consequence of violating the LCO limits is that the PCS has been operated under conditions that can result in brittle failure of the PCPB, 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 PCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), 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 PCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

The PCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2).

BASES

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 PCS, 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. Additional cooldown rate restrictions were put in place due to the reactor vessel head nozzle repairs per Reference 7. 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 PCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The PCS P/T limits Specification provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2) and due to the reactor vessel nozzle repairs (Ref. 7). 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 additional cooldown rate restrictions for the reactor vessel nozzle repairs only apply when the reactor vessel head is on the reactor vessel. The limits do not apply to the pressurizer.

BASES

APPLICABILITY (continued)

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, "PCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "PCS 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.

The actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures.

ACTIONS

A.1 and A.2

Operation outside the P/T limits must be corrected so that the PCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation to within limits, an evaluation is required to determine if PCS operation can continue. The evaluation must verify the PCPB 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. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

BASES

ACTIONS

A.1 and A.2 (continued)

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 PCPB 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:

a. The PCS remained in an unacceptable P/T region for an extended period of increased stress; or

b. A sufficiently severe event caused entry into an unacceptable region.

Either possibility indicates a need for more careful examination of the event, best accomplished with the PCS at reduced pressure and temperature. With reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is generally decreased.

Pressure and temperature are reduced by placing the plant in MODE 3 within 6 hours and in MODE 5 with PCS pressure < 270 psia within 36 hours.

The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

The actions of this LCO, anytime other than in MODE 1, 2, 3, or 4, consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures. Operation outside the P/T limits must be corrected so that the PCPB is returned to a condition that has been verified by stress analyses.

The Completion Time of "immediately" 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 a short period of time in a controlled manner.

Besides restoring operation to within limits, an evaluation is required to determine if PCS operation can continue. The evaluation must verify that the PCPB 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. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The Completion Time of prior to entering MODE 4 forces the evaluation prior to entering a MODE where temperature and pressure can be significantly increased. The evaluation for a mild violation is possible within several days, but more severe violations may require special, event specific stress analyses or inspections.

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 PCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the limits of Figure 3.4.3-1 and Figure 3.4.3-2 is required every 30 minutes when PCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor PCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time. Calculation of the average hourly cooldown rate must consider changes in reactor vessel inlet temperature caused by initiating shutdown cooling, by starting primary coolant pumps with a temperature difference between the steam generator and PCS, or by stopping primary coolant pumps with shutdown cooling in service. The additional restrictions in Figure 3.4.3-2, required for the reactor vessel head nozzle repairs, use the average core exit temperature to provide the best indication available of the temperature of the head inside material temperature. This indication may be either the average of the core exit thermocouples or the vessel outlet temperature.

Surveillance for heatup and cooldown operations may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that requires this SR be performed only during PCS heatup and cooldown operations. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. Safety Evaluation for Palisades Nuclear Plant License Amendment No. 163, dated March 2, 1995
2. 10 CFR 50, Appendix G
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G
4. ASTM E 185-82, July 1982
5. 10 CFR 50, Appendix H
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E
7. Safety Evaluation for Palisades Nuclear Plant License Amendment No. 218, dated November 8, 2004

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

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 safety valves are addressed by LCO 3.4.10. The PORVs are solenoid-pilot operated relief valves which, when placed in the "Auto" position, automatically open at a specific set pressure when the pressurizer pressure increases and is automatically closed on decreasing pressure. The PORV may also be manually operated using controls installed in the control room.

A motor operated, normally closed, block valve is installed between the pressurizer and each PORV. The function of the block valve is to isolate the PORV. Block valve closure is accomplished manually using controls in the control room and may be used to isolate a leaking PORV to permit continued power operation. Most importantly, the block valve is used to isolate a stuck open PORV to isolate the resulting Loss Of Coolant Accident (LOCA). Closure terminates the PCS depressurization and coolant inventory loss.

The PORV, its block valve, and their respective controls are powered from safety class power supplies. Power supplies for the PORV are separate from those for the block valve. Power supply requirements are defined in NUREG-0737, Item II.G.1.

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

In the event of an abnormal transient, the PORVs may be manually operated to depressurize the PCS as directed by the Emergency Operating Procedures. The PORVs may be used for depressurization when the pressurizer spray is not available, a condition that may be encountered during a loss of offsite power. Operators can manually open the PORVs to reduce PCS pressure in the event of a Steam Generator Tube Rupture (SGTR) with offsite power unavailable.

The PORVs may also be used for once-through core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

BASES

BACKGROUND (continued)

If preferred during normal plant operation when PCS temperature is at or above 430°F and the PORV block valves are open, the PORVs may also function as an automatic overpressure device and limits challenges to the safety valves. Although the PORVs act as an overpressure device for operational purposes, safety analyses do not take credit for PORV actuation, but do take credit for the safety valves. Since the pressurizer safety valves provide the necessary automatic protection against excessive PCS pressure, automatic actuation of the PORVs is not required to be OPERABLE and the PORVs and their block valves are normally maintained in the closed position.

The PORVs also provide Low Temperature Overpressure Protection (LTOP) during heatup and cooldown. LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," addresses this function.

APPLICABLE SAFETY ANALYSES

The PORV small break LOCA break size is bounded by the spectrum of piping breaks analyzed for plant licensing. The possibility of a small break LOCA through the PORV is reduced when the PORV flow path is OPERABLE and the PORV opening setpoint is established to be reasonably remote from expected transient challenges. The possibility is further minimized if the flow path is isolated.

Overpressure protection is provided by safety valves, and analyses do not take credit for the PORV opening for accident mitigation. However, technical findings and regulatory analysis discussed in NUREG-1316, "Technical Findings and Regulatory Analysis Related to Generic Issue 70 - Evaluation of Power-Operated Relief Valve and Block Valve Reliability in PWR Nuclear Power Plants," have determined that maintaining the requirements for PORVs and block valves in the technical specifications can increase the reliability of these components and provide assurance they will function as required and that operating experience has shown these components to be important to public health and safety.

Pressurizer PORVs satisfy Criterion 4 of 10 CFR 50.36(c)(2).

BASES

LCO

The LCO requires each PORV and its associated block valve to be OPERABLE. The block valve is required to be OPERABLE so it may be used to isolate the flow path of an inoperable PORV or, unisolate the flow path of an OPERABLE PORV. Thus, a block valve is considered OPERABLE if it is capable of being cycled in the open and close direction.

The PORV is required to be OPERABLE to provide PCS pressure control and maintain PCS integrity. For a PORV, OPERABILITY means the valve is capable of being cycled in the open and close direction.

APPLICABILITY

With a PORV in the "CLOSED" position in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F, the PORV and its block valve are required to be OPERABLE to limit PCS leakage through the PORV flow path, and to be available for manual operation to mitigate abnormal transients which may be initiated from these MODES and condition.

With a PORV in the "AUTO" position in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. A likely cause for PORV small break LOCA is a result of pressure increase transients that cause the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the PCS pressure to increase to the PORV opening setpoint. Pressure increase transients can occur any time the steam generators are used for heat removal. The most rapid increases will occur at higher operating power and pressure conditions of MODES 1 and 2. Pressure increases are less prominent in MODE 3 with PCS cold leg temperatures < 430°F because the core input energy is reduced, but the PCS pressure is high. Therefore, this LCO is applicable in MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F.

The LCO is not applicable in MODE 3 with any PCS cold leg temperatures < 430°F when both pressure and core energy are decreased and the pressure surges become much less significant. The PORV setpoint is reduced for LTOP in MODE 3 when any PCS cold leg temperatures are < 430°F, and in MODES 4, 5, and MODE 6 with the reactor vessel head in place. LCO 3.4.12 addresses the PORV requirements in these MODES.

BASES

ACTIONS

The ACTIONS are modified by a Note. The Note clarifies that each pressurizer PORV is treated as a separate entity, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1 and A.2

If one PORV is inoperable it must either be isolated, by closing the associated block valve, or restored to OPERABLE status. The Completion Time of 1 hour is reasonable based on the small potential that the PORVs will be required to function during this time period and provides 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. Mechanical system LCOs typically provide a 72 hour Completion Time under conditions when a required system can perform its required safety function, but may not be able to do so assuming an additional failure. When operating in accordance with the Required Actions of an LCO Condition, it is not necessary to be able to cope with an additional single failure

B.1 and B.2

If one block valve is inoperable, then it must be restored to OPERABLE status, or the associated PORV placed in manual control. Placing a PORV in manual control is accomplished by placing the PORV hand switch in the "CLOSE" position. 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 that the PORVs will be required to function 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.

BASES

ACTIONS (continued)

B.1 and B.2

Mechanical system LCOs typically provide a 72 hour Completion Time under conditions when a required system can perform its required safety function, but may not be able to do so assuming an additional failure. When operating in accordance with the Required Actions of an LCO Condition, it is not necessary to be able to cope with an additional single failure.

The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition A since the PORVs are not capable of automatically mitigating an overpressure event when placed in manual control. If the block valve is restored within the Completion Time of 72 hours, the PORV is restored to OPERABLE status.

C.1 and C.2

If more than one PORV is inoperable, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing the associated block valves and restoring at least one PORV to OPERABLE status within 2 hours. The Completion Time of 1 hour is reasonable based on the small potential that the PORVs will be required to function during this time period, 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 A with the time clock started at the original declaration of having two PORVs inoperable.

D.1 and D.2

If two block valves are inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour or place the associated PORVs in manual control and restore at least one block valve to OPERABLE status within 2 hours and the remaining block valve in 72 hours. The Completion Time of 1 hour to either restore the block valves or place the associated PORVs in manual control is reasonable based on the small potential that the PORVs will be required to function during this time period, and provides the operator time to correct the situation.

BASES

ACTIONS (continued)

E.1

If the Required Actions and associated Completion Times are not met, then the plant must be brought to a stable condition which minimizes the potential for transients affecting the PCS. The plant must be brought to at least MODE 3 within 6 hours. With one or two PORVs or block valves inoperable, exiting the MODE of Applicability (i.e., MODE 3 with any PCS cold leg temperature < 430°F) may not be desirable since below 430°F the PORVs and their associated block valves are required to support LTOP operations (LCO 3.4.12). Although LCO 3.0.4 would allow entry into LCO 3.4.12, reducing PCS temperature below 430°F may not be prudent since below 430°F the PORVs are credited in the safety analysis to protect the PCS from an inadvertent overpressure event. At or above 430°F, the PORVs are not credited in the safety analysis and thus have no safety function. If practical, the inoperable PORVs or block valves should be restored to an OPERABLE status while the PCS is above 430°F to avoid entering a plant condition where the PORVs are required for LTOP. If necessary, LCO 3.0.4 would allow the plant to be placed in MODE 5 to facilitate repairs. In this plant condition, overpressure protection may be provided by establishing the required vent path specified in LCO 3.4.12.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging safety systems. In MODE 3 with any PCS cold leg temperature < 430°F, and MODES 4 and 5 and MODE 6 with the reactor vessel head on, maintaining PORV OPERABILITY is required by LCO 3.4.12.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that it can be opened and closed if necessary. The basis for the Frequency of "prior to entering MODE 4 from MODE 5 if not performed in the previous 92 days" reflects the importance of not routinely cycling the block valves during the period when the PCS is pressurized since this practice may result in the associated PORV being opened by the increase inlet pressure to the PORV. The "92 days" portion of the Frequency is consistent with the testing frequency stipulated by ASME Section XI as modified by the Cold Shutdown Testing Basis used in support of the second 120 month interval of the Inservice Valve Testing Program which only requires the block valves to be cycled during Cold Shutdown conditions. If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is of importance because opening the block valve is necessary to permit the PORV to be used for manual control of primary coolant pressure. If a block valve is open and its associated PORV was stuck open, the OPERABILITY of the block valve is of importance because closing the block valve is necessary to isolate the stuck opened PORV.

SR 3.4.11.2

SR 3.4.11.2 requires complete cycling of each PORV. PORV cycling demonstrates its function and is performed when the PCS temperature is > 200°F. Stroke testing of the PORVs above 200°F is desirable since it closer simulates the temperature and pressure environmental effects on the valves and thus represents a better test condition for assessing PORV performance under normal plant conditions. The Frequency of 18 months is based on a typical refueling cycle and industry accepted practice.

REFERENCES

None

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls PCS pressure at low temperatures so the integrity of the Primary Coolant Pressure Boundary (PCPB) 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 PCPB component requiring such protection. LCO 3.4.3, "PCS Pressure and Temperature (P/T) Limits," provides the allowable combinations for operational pressure and temperature during cooldown, shutdown, and heatup to keep from violating the Reference 1 requirements during the LTOP MODES.

The toughness of the reactor vessel material decreases at low temperatures. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). PCS 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 PCS is water solid, which occurs only while shutdown. Under that condition, a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the PCS P/T limits by a significant amount could cause brittle fracture of the reactor vessel. LCO 3.4.3 requires administrative control of PCS pressure and temperature during heatup and cooldown to prevent exceeding the P/T limits.

This LCO provides PCS overpressure protection by limiting coolant injection capability and requiring adequate pressure relief capacity. Limiting coolant injection capability requires all High Pressure Safety Injection (HPSI) pumps be incapable of injection into the PCS when any PCS cold leg temperature is < 300°F. The pressure relief capacity requires either two OPERABLE redundant Power Operated Relief Valves (PORVs) or the PCS depressurized and a PCS vent of sufficient size. One PORV or the PCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

BASES

BACKGROUND (continued)

With limited coolant injection capability, the ability to provide core coolant addition is restricted. The LCO does not require the chemical and volume control system to be deactivated or the Safety Injection Signals (SIS) blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the chemical and volume control system can provide adequate flow via the makeup control valve. If conditions require the use of an HPSI pump for makeup in the event of loss of inventory, then a pump can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with temperature dependent lift settings or a PCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to prevent overpressurization for the allowed coolant injection capability.

PORV Requirements

As designed for the LTOP System, an "open" signal is generated for each PORV if the PCS pressure approaches a limit determined by the LTOP actuation logic. The actuation logic monitors PCS pressure and cold leg temperature to determine when the LTOP overpressure setting is approached. If the indicated pressure meets or exceeds the calculated value, a PORV is opened.

The LCO presents the PORV setpoints for LTOP by specifying Figure 3.4.12-1, "LTOP Setpoint Limit." Having the setpoints of both valves within the limits of the LCO ensures the P/T limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant causes the pressure increase to slow and reverse. As the PORV releases coolant, the system pressure decreases until a reset pressure is reached and the valve closed. The pressure continues to decrease below the reset pressure as the valve closes.

BASES

BACKGROUND (continued)

PCS Vent Requirements

Once the PCS is depressurized, a vent exposed to the containment atmosphere will maintain the PCS at containment ambient pressure in an PCS 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 injection or heatup transient and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Reference 3 has determined that any vent path capable of relieving 167 gpm at a PCS pressure of 315 psia is acceptable. The 167 gpm flow rate is based on an assumed charging imbalance due to interruption of letdown flow with three charging pumps operating, a 40°F per hour PCS heatup rate, a 60°F per hour pressurizer heatup rate, and an initially depressurized and vented PCS. Neither HPSI pump nor Primary Coolant Pump (PCP) starts need to be assumed with the PCS initially depressurized, because LCO 3.4.12 requires both HPSI pumps to be incapable of injection into the PCS and LCO 3.4.7, "PCS Loops-MODE 5, Loops Filled," places restrictions on starting a PCP.

The pressure relieving ability of a vent path depends not only upon the area of the vent opening, but also upon the configuration of the piping connecting the vent opening to the PCS. A long, or restrictive piping connection may prevent a larger vent opening from providing adequate flow, while a smaller opening immediately adjacent to the PCS could be adequate. The areas of multiple vent paths cannot simply be added to determine the necessary vent area.

The following vent path examples are acceptable:

1. Removal of a steam generator primary manway;
2. Removal of the pressurizer manway;
3. Removal of a PORV or pressurizer safety valve;
4. Both PORVs and associated block valves open; and
5. Opening of both PCS vent valves MV-PC514 and MV-PC515.

BASES

BACKGROUND (continued)

Reference 4 determined that venting the PCS through MV-PC514 and MV-PC515 provided adequate flow area. The other listed examples provide greater flow areas with less piping restriction and are therefore acceptable. Other vent paths shown to provide adequate capacity could also be used. The vent path(s) must be above the level of reactor coolant, to prevent draining the PCS.

One open PORV provides sufficient flow area to prevent excessive PCS pressure. However, if the PORVs are elected as the vent path, both valves must be used to meet the single failure criterion, since the PORVs are held open against spring pressure by energizing the operating solenoid.

When the shutdown cooling system is in service with MO-3015 and MO-3016 open, additional overpressure protection is provided by the relief valves on the shutdown cooling system. References 5 and 6 show that this relief capacity will prevent the PCS pressure from exceeding its pressure limits during any of the above mentioned events.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 7) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits during shutdown. In MODES 1 and 2, and in MODE 3 with all PCS cold leg temperature at or exceeding 430°F, the pressurizer safety valves prevent PCS pressure from exceeding the Reference 1 limits. Below 430°F, overpressure prevention falls to the OPERABLE PORVs or to a depressurized PCS and a sufficiently sized PCS 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 P/T limit curves are revised, the LTOP System should be re-evaluated to ensure its functional requirements can still be satisfied using the PORV method or the depressurized and vented PCS condition.

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

Transients that are capable of overpressurizing the PCS are categorized as either mass injection or heatup transients

Mass Injection Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

Heatup Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of Shutdown Cooling (SDC); or

c. PCP startup with temperature asymmetry within the PCS or between the PCS and steam generators.

Rendering both HPSI pumps incapable of injection is required during the LTOP MODES to ensure that mass injection transients beyond the capability of the LTOP overpressure protection system, do not occur. The Reference 3 analyses demonstrate that either one PORV or the PCS vent can maintain PCS pressure below limits when three charging pump are actuated. Thus, the LCO prohibits the operation of both HPSI pumps and does not place any restrictions on charging pump operation.

Fracture mechanics analyses were used to establish the applicable temperature range for the LTOP LCO as below 430°F. At and above this temperature, the pressurizer safety valves provide the reactor vessel pressure protection. The vessel materials were assumed to have a neutron irradiation accumulation equal to 2.192 E19 nvt.

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the setpoint curve specified in Figure 3.14.12-1 of the accompanying LCO. The setpoint is derived by modeling the performance of the LTOP System, assuming the limiting allowed LTOP transient. The valve qualification process considered pressure overshoot and undershoot beyond the PORV opening and closing setpoints, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensure the Reference 1 limits will be met.

The PORV setpoints will be re-evaluated for compliance when the P/T limits are revised. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to embrittlement caused by neutron irradiation. Revised P/T limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3 discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV represents the worst case, single active failure.

PCS Vent Performance

With the PCS depressurized, analyses show the required vent size is capable of mitigating the limiting allowed LTOP overpressure transient. In that event, this size vent maintains PCS pressure less than the maximum PCS pressure on the P/T limit curve.

The PCS vent is passive and is not subject to active failure.

LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2).

BASES

LCO

This LCO is required to ensure that the LTOP System is OPERABLE. The LTOP System is OPERABLE when both HPSI pumps are incapable of injecting into the PCS 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 injection capability, LCO 3.4.12.a requires both HPSI pumps be incapable of injecting into the PCS. LCO 3.4.12.a is modified by two Notes. Note 1 only requires both HPSI pumps to be incapable of injecting into the PCS when any PCS cold leg temperature is < 300°F. When all PCS cold leg temperatures are ≥ 300°F, a start of both HPSI pumps in conjunction with a charging/letdown imbalance will not cause the PCS pressure to exceed the 10 CFR 50 Appendix G limits. Thus, a restriction on HPSI pump operation when all PCS cold leg temperatures are ≥ 300°F is not required. Note 2 is provided to assure that this LCO does not cause hesitation in the use of a HPSI pump for PCS makeup if it is needed due to a loss of shutdown cooling or a loss of PCS inventory.

The elements of the LCO that provide overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

b. The PCS depressurized and vented.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set consistent with Figure 3.4.12-1 in the accompanying LCO and testing has proven its ability to open at that setpoint, and motive power is available to the valve and its control circuit.

A PCS vent is OPERABLE when open with an area capable of relieving ≥ 167 gpm at a PCS pressure of 315 psia.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

BASES

APPLICABILITY

This LCO is applicable in MODE 3 when the temperature of any PCS cold leg is < 430°F, in MODES 4 and 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits at and above 430°F. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1 and 2, and MODE 3 with all PCS cold leg temperatures ≥ 430°F.

Low temperature overpressure prevention is most critical during shutdown when the PCS is water solid, and a mass addition or a heatup transient can cause a very rapid increase in PCS pressure with little or no time available for operator action to mitigate the event.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to inoperable PORVs used for LTOP. There is an increased risk associated with entering MODE 4 from MODE 5 with PORVs used for LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

<u>A.1</u>

With one or two HPSI pumps capable of injecting into the PCS, overpressurization is possible.

The immediate Completion Time to initiate actions to restore restricted coolant injection capability to the PCS reflects the importance of maintaining overpressure protection of the PCS.

BASES

ACTIONS (continued)

B.1

With one required PORV inoperable and pressurizer water level ≤ 57%, the required PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two valves are required to meet the LCO requirement and to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time is based on only one PORV being required to mitigate an overpressure transient, the likelihood of an active failure of the remaining valve path during this time period being very low, and that a steam bubble exists in the pressurizer. Since the pressure response to a transient is greater if the pressurizer steam space is small or if the PCS is solid, the Completion Time for restoration of a PORV flow path to service is shorter. The maximum pressurizer level at which credit can be taken for having a bubble (57%, which provides about 700 cubic feet of steam space) is based on judgement rather than by analysis. This level provides the same steam volume to dampen pressure transients as would be available at full power. This steam volume provides time for operator action (if the PORVs failed to operate) in the interval between an inadvertent SIS and PCS pressure reaching the 10 CFR 50, Appendix G pressure limit. The time available for action would depend upon the existing pressure and temperature when the inadvertent SIS occurred.

C.1

The consequences of operational events that will overpressurize the PCS are more severe at lower temperature (Ref. 8). With the pressurizer water level > 57%, less steam volume is available to dampen pressure increases resulting from an inadvertent mass injection or heatup transients. Thus, with one required PORV inoperable and the pressurizer water level > 57%, the Completion Time to restore the required PORV to OPERABLE status is 24 hours.

The 24 hour Completion Time to restore the required PORV to OPERABLE status when the pressurizer water level is > 57%, which usually occurs in MODE 5 or in MODE 6 when the vessel head is on, is a reasonable amount of time to investigate and repair PORV failures without a lengthy period with only one PORV OPERABLE to protect against overpressure events.

BASES

ACTIONS (continued)

D.1

If two required PORVs are inoperable, or if the Required Actions and the associated Completion Times are not met, or if the LTOP System is inoperable for any reason other than Condition A, B, or C, the PCS must be depressurized and a vent established within 8 hours. The vent must be sized to provide a relieving capability of ≥ 167 gpm at a pressure of 315 psia which ensures the flow capacity is greater than that required for the worst case mass injection transient reasonable during the applicable MODES. This action protects the PCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time of 8 hours to depressurize and vent the PCS is based on 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 operator attention and administrative requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

To minimize the potential for a low temperature overpressure event by limiting the mass injection capability, both HPSI pumps are verified to be incapable of injecting into the PCS. The HPSI pumps are rendered incapable of injecting into the PCS by means that assure that a single event cannot cause overpressurization of the PCS due to operation of the pump. Typical methods for accomplishing this are by pulling the HPSI pump breaker control power fuses, racking out the HPSI pump motor circuit breaker, or closing the manual discharge valve.

SR 3.4.12.1 is modified by a Note which only requires the SR to be met when complying with LCO 3.4.12.a. When all PCS cold leg temperature are ≥ 300°F, a start of both HPSI pumps in conjunction with a charging/letdown imbalance will not cause the PCS pressure to exceed the 10 CFR 50 Appendix G limits. Thus, this SR is only required when any PCS cold leg temperature is reduced to less than 300°F.

The 12 hour interval considers operating practice to regularly assess potential degradation and to verify operation within the safety analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.2

SR 3.4.12.2 requires a verification that the required PCS vent, capable of relieving ≥ 167 gpm at a PCS pressure of 315 psia, is OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked open; or

b. Once every 31 days for a valve that is locked open.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance need only be performed if vent valves are being used to satisfy the requirements of this LCO. This Surveillance does not need to be performed for vent paths relying on the removal of a steam generator primary manway cover, pressurizer manway cover, safety valve or PORV since their position is adequately addressed using administrative controls and the inadvertent reinstallation of these components is unlikely. The Frequencies consider operating experience with mispositioning of unlocked and locked vent valves, respectively.

SR 3.4.12.3

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve can be remotely verified open in the main control room.

The block valve is a remotely controlled, motor operated valve. The power to the valve motor operator is not required to be removed, and the manual actuator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure event.

The 72 hour Frequency considers operating experience with accidental movement of valves having remote control and position indication capabilities available where easily monitored. These considerations include the administrative controls over main control room access and equipment control.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

Performance of a CHANNEL FUNCTIONAL TEST is required every 31 days. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay This is acceptable because all of the Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. PORV actuation could depressurize the PCS and is not required. The 31 day Frequency considers experience with equipment reliability.

A Note has been added indicating this SR is required to be performed 12 hours after decreasing any PCS cold leg temperature to < 430°F. This Note allows a discrete period of time to perform the required test without delaying entry into the MODE of Applicability for LTOP. This option may be exercised in cases where an unplanned shutdown below 430°F is necessary as a result of a Required Action specifying a plant shutdown, or other plant evolutions requiring an expedited cooldown of the plant. The test must be performed within 12 hours after entering the LTOP MODES.

SR 3.4.12.5

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months to adjust the entire channel so that it responds and the valve opens within the required LTOP range and with accuracy to known input.

The 18 month Frequency considers operating experience with equipment reliability and is consistent with the typical refueling outage schedule.

BASES

REFERENCES

1. 10 CFR 50, Appendix G
2. Generic Letter 88-11
3. CPC Engineering Analysis, EA-A-PAL-92-095-01
4. CPC Engineering Analysis, EA-TCD-90-01
5. CPC Engineering Analysis, EA-E-PAL-89-040-1
6. CPC Corrective Action Document, A-PAL-91-011
7. FSAR, Section 7.4
8. Generic Letter 90-06

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.15 PCS Leakage Detection Instrumentation

BASES

BACKGROUND

The Palisades Nuclear Plant design criteria (Ref. 1) require means for detecting and, to the extent practical, identifying the location of the source of PCS LEAKAGE.

Leakage detection instrumentation must have the capability to detect significant Primary Coolant Pressure Boundary (PCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 gpm to 1.0 gpm can readily be detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump, which is used to collect unidentified LEAKAGE, is instrumented with level transmitters providing sump level indication in the control room. The sensitivity of these instruments is acceptable for detecting increases in unidentified LEAKAGE.

The primary coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Primary coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. An instrument sensitivity capable of detecting a 100 cm^3/min leak in 45 minutes based on 1% failed fuel is practical for the leakage detection instrument (Ref. 2). Radioactivity detection is included for monitoring gaseous activities because of its sensitivity to PCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Humidity detectors are capable of detecting a 10% change in humidity which would result from approximately 150 gallons of primary water leakage (Ref. 2).

BASES

BACKGROUND (continued)

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

The containment air cooler design includes a sump with a drain, a liquid level switch, and an overflow path. Normally, very little water will be condensed from the containment atmosphere and the small amount of condensate will easily flow out through the sump drain. If flow to the sump is greater than 20 gpm, the level in the sump will rise to the liquid level switch (approximately 6 inches from the bottom of the sump) and triggers an alarm in the control room. Excessive flow to the sump is indicative of a service water leak, steam leak, or a primary coolant system leak. A steam leak or primary coolant leak would be accompanied by an increase in the containment atmosphere humidity which would be detected by the containment humidity sensors and displayed in the control room. Since excessive containment air cooler drainage may be attributed to causes other than PCS LEAKAGE, an evaluation of PCS LEAKAGE should be confirmed using diverse instrumentation required by this specification.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate during plant operation, but a rise above the normally indicated range of values may indicate PCS LEAKAGE into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

BASES

APPLICABLE SAFETY ANALYSES	The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system sensitivities are described in the FSAR (Ref. 2). Multiple instrument locations are utilized, if needed, to ensure the transport delay time of the LEAKAGE from its source to an instrument location is acceptable. The safety significance of PCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring PCS LEAKAGE into the containment area are necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should leakage occur detrimental to the safety of the facility and the public. PCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2).
LCO	One method of protecting against large PCS LEAKAGE is based on the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition when PCS LEAKAGE indicates possible PCPB degradation. The LCO is satisfied when monitors of diverse measurement means are available. Thus, a combination which includes one instrument channel from each of any three of the following; containment sump level indication, gaseous activity monitor, containment air cooler condensate level switch, or containment humidity monitor provides an acceptable minimum. For the containment air cooler condensate level switch only an operating containment air cooler may be relied upon to fulfill the LCO requirements for an OPERABLE leakage detection instrument.
APPLICABILITY	Because of elevated PCS temperature and pressure in MODES 1, 2, 3, and 4, PCS leakage detection instrumentation is required to be OPERABLE. In MODE 5 or 6, the temperature is ≤ 200°F and pressure is maintained low or at atmospheric pressure.

BASES

APPLICABILITY (continued)

Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation is much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

If one or two required leak detection instrument channels are inoperable, a periodic surveillance for PCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

As stated in SR 3.0.2, the 25% extension allowed by SR 3.0.2 may be applied to Required Actions whose Completion Time is stated as "once per . . ." however, the 25% extension does not apply to the initial performance of a Required Action with a periodic Completion Time that requires performance on a "once per. . ." basis. The 25% extension applies to each performance of the Required Action after the initial performance. Therefore, while Required Action 3.4.15 A.1 must be initially performed within 24 hours without any SR 3.0.2 extension, subsequent performances may utilize the 25% SR 3.0.2 extension.

Restoration of the required instrument channels to an OPERABLE status is required to regain the function in a Completion Time of 30 days after the instrument's failure. This time is acceptable considering the frequency and adequacy of the PCS water inventory balance required by Required Action A.1.

B.1 and B.2

If the Required Action cannot be met 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

ACTIONS (continued)

C.1

If all required monitors are 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 3.4.15.2, and SR 3.4.15.3

These SRs require the performance of a CHANNEL CHECK for each required containment sump level indicator, containment atmosphere gaseous activity monitor, and containment atmosphere humidity monitor. The check gives reasonable confidence the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.4

SR 3.4.15.4 requires the performance of a CHANNEL FUNCTIONAL TEST of the required containment air cooler condensate level switch. Since this instrumentation does not include control room indication of flow rate, a CHANNEL CHECK is not possible. The test ensures that the level switch can perform its function in the desired manner. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency of 18 months is a typical refueling cycle (performance of the test is only practical during a plant outage) and considers instrument reliability. Operating experience has shown this Frequency is acceptable for detecting degradation.

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.4.15.5, SR 3.4.15.6, and SR 3.4.15.7 These SRs require the performance of a CHANNEL CALIBRATION for each required containment sump level, containment atmosphere gaseous activity, and containment atmosphere humidity channel. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Operating experience has shown this Frequency is acceptable.
REFERENCES	1. FSAR, Section 5.1.5 2. FSAR, Sections 4.7 and 6.3

B 3.4 PRIMARY COOLANT SYSTEM (PCS)

B 3.4.16 PCS Specific Activity

BASES

BACKGROUND

10 CFR 100.11 specifies the maximum dose to the whole body and the thyroid an individual at the site boundary can receive for 2 hours during an accident. The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 guideline limits during analyzed transients and accidents.

The PCS specific activity LCO limits the allowable concentration level of radionuclides in the primary coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a Steam Generator Tube Rupture (SGTR) accident.

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

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

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the primary coolant ensure that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following an SGTR accident. The SGTR safety analysis (Ref. 1) assumes the specific activity of the primary coolant at the LCO limits and an existing primary coolant Steam Generator (SG) tube leakage rate of 0.3 gpm. The analysis also assumes a reactor trip and a turbine trip at the same time as the SGTR event.

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

The rise in pressure in the ruptured SG causes radioactive contaminated steam to discharge to the atmosphere through the atmospheric dump valves or the main steam safety valves. The atmospheric discharge stops when the affected SG is isolated below approximately 525°F. The unaffected SG removes core decay heat by venting steam until Shutdown Cooling conditions are reached.

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the 10 CFR 100 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limit of 40 μCi/gm for more than 48 hours.

This is acceptable because of the low probability of an SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

PCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2).

LCO

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

The SGTR accident analysis (Ref. 1) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in primary coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits.

BASES

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with PCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity is necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values.

For operation in MODE 3 with PCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of an SGTR is unlikely since the saturation pressure corresponding to the primary coolant temperature is below the lift settings of the atmospheric dump valves and main steam safety valves.

ACTIONS

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS.

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 the limit 40 µCi/gm is not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample.

As stated in SR 3.0.2, the 25% extension allowed by SR 3.0.2 may be applied to Required Actions whose Completion Time is stated as "once per . . ." however, the 25% extension does not apply to the initial performance of a Required Action with a periodic Completion Time that requires performance on a "once per. . ." basis. The 25% extension applies to each performance of the Required Action after the initial performance. Therefore, while Required Action 3.4.16 A.1 must be initially performed within 4 hours without any SR 3.0.2 extension, subsequent performances may utilize the 25% SR 3.0.2 extension.

Sampling must continue for trending. 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 to the Required Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception 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.

BASES

ACTIONS (continued)

B.1

If a Required Action and associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is 40 µCi/gm or above, or with the gross specific activity in excess of the allowed limit, the plant must be placed in a MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 with PCS average temperature < 500°F lowers the saturation pressure of the primary 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 required to reach MODE 3 below 500°F from full power conditions and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

The Surveillance requires performing a gamma isotopic analysis as a measure of the gross specific activity of the primary coolant at least once per 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with PCS average temperature at least 500°F. The 7 day Frequency considers the unlikelihood of a gross fuel failure during the time.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance is performed to ensure iodine remains within limits during normal operation and following fast power changes when fuel failure is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level considering gross activity is monitored every 7 days. The Frequency, between 2 hours and 6 hours after any power change of ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results. If any (may be more than one) power change ≥ 15% RTP occurs within a 1 hour period, then more than one sample may be required to ensure that an iodine peak sample is obtained between the 2 and 6 hour Frequency requirement. This SR is modified by a Note which states that the SR is only required to be performed in MODE 1. Entrance into a lower MODE does not preclude completion of this surveillance.

SR 3.4.16.3

A radiochemical analysis for Ē determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The Ē determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for Ē is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Frequency of 184 days recognizes Ē does not change rapidly.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after 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 the radioactive materials are at equilibrium so the analysis for Ē is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. FSAR, Section 14.15

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND	The ADVs provide a method for cooling the plant to Shutdown Cooling (SDC) System entry conditions, should the preferred heat sink via the turbine bypass valve to the condenser not be available, as discussed in the FSAR, Section 10.2 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the Condensate Storage Tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the turbine bypass valve. Four ADVs are provided, two per steam generator. One ADV per steam generator is required following an event rendering one steam generator unavailable for Primary Coolant System (PCS) heat removal. The ADVs are provided with upstream manual isolation valves to provide a means of isolation in the event an ADV spuriously opens, or fails to close during use. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate. The ADVs are provided with a pressurized gas supply from the Bulk Nitrogen System that, on a loss of pressure in the normal instrument air supply, automatically supplies nitrogen to operate the ADVs. The nitrogen backup is not required for ADV OPERABILITY. A description of the nitrogen backup is found in the FSAR, Section 9.5.2 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The design basis of the ADVs is to prevent lifting of the Main Steam Safety Valves (MSSVs) following a turbine and reactor trip, and to provide the capability to cool the plant to SDC System entry conditions when condenser vacuum is lost. A cooldown rate of approximately 75°F per hour is obtainable by one or both steam generators. This design is adequate to cool the plant to SDC System entry conditions with only one ADV and one steam generator, utilizing the cooling water supply available in the Condensate Storage and Supply system.

BASES

APPLICABLE SAFETY ANALYSES (continued)	In certain accident analyses presented in the FSAR, the ADVs are assumed to be used by the operator to cool down the plant to SDC System entry conditions for accidents accompanied by a loss of offsite power. The ADVs are credited for cooldown during a Steam Generator Tube Rupture (SGTR) event. Prior to the operator action, the Main Steam Safety Valves (MSSVs) are used to maintain steam generator pressure and temperature at or below the MSSV setpoint for 30 minutes following the initiation of an event. The ADVs are also credited in selected safety analyses when the Auxiliary Feedwater (AFW) System is required to operate. If AFW pump P-8C is used, operator action may be required to either trip the four Primary Coolant Pumps (PCPs), start an additional AFW pump, or reduce steam generator pressure. This will allow the required AFW flowrate to the steam generators assumed by the loss of feedwater analysis. The ADVs are equipped with manual isolation valves in the event an ADV spuriously opens, or fails to close during use. The ADVs satisfy Criterion 3 of 10 CFR 50.36(c)(2).
LCO	One ADV is required to be OPERABLE on each steam generator to ensure that at least one ADV is OPERABLE to conduct a plant cooldown following an event in which one steam generator becomes unavailable. A closed manual isolation valve does not render its ADV inoperable, since operator action time to open the manual isolation valve is supported in the accident analysis. Failure to meet the LCO can result in the inability to cool the plant to SDC System entry conditions following an event in which the condenser is unavailable for use with the turbine bypass valve. An ADV is considered OPERABLE when it is capable of providing a controlled relief of the main steam flow, and is capable of fully opening and closing on demand from either the control room or Hot Shutdown Panel (C-33).
APPLICABILITY	In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE. In MODES 5 and 6, there are no credible transients requiring ADVs.

BASES

ACTIONS

A.1

With one required ADV inoperable, action must be taken to restore the ADV to OPERABLE status within 7 days. The 7 day Completion Time takes into account the redundant capability afforded by the remaining OPERABLE ADV, and a nonsafety grade backup in the turbine bypass valve and MSSVs.

B.1

With two required ADVs inoperable, action must be taken to restore one of the ADVs to OPERABLE status. As the manual isolation valve can be closed to isolate an ADV, some repairs may be possible with the plant at power. The 24 hour Completion Time is reasonable to repair inoperable ADVs, based on the availability of the turbine bypass valve and MSSVs, and the low probability of an event occurring during this period that requires the ADVs.

C.1 and C.2

If the ADVs cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon the steam generator for heat removal, within 30 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 3.7.4.1

To perform a controlled cooldown of the PCS, the ADVs must be able to be cycled through their full range. This SR ensures the ADVs are tested through a full control cycle at least once per 18 months. Performance of inservice testing or use of an ADV during a plant cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 10.2

2. FSAR, Section 9.5.2

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 Primary Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through a common suction line from the Condensate Storage Tank (CST) (LCO 3.7.6, "Condensate Storage and Supply") and pump to the steam generator secondary side via two separate and independent flow paths to a common AFW supply header for each steam generator. 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 Dump Valves (ADVs) (LCO 3.7.4, "Atmospheric Dump Valves (ADVs)"). If the main condenser is available, steam may be released via the turbine bypass valve.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into two trains. One train (A/B) consists of a motor driven pump (P-8A) and the turbine driven pump (P-8B) in parallel, the discharges join together to form a common discharge. The A/B train common discharge separates to form two flow paths, which feed each steam generator via each steam generator's AFW penetration. The second motor driven pump (P-8C) feeds both steam generators through separate flow paths via each steam generator AFW penetration and forms the other train (C). The two trains join together at each AFW penetration to form a common supply to the steam generators. Each AFW pump is capable of providing 100% of the required capacity to the steam generators as assumed in the accident analysis. The pumps are equipped with independent 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 both steam generators.

BASES

BACKGROUND (continued)

The steam turbine driven AFW pump receives steam from the steam generator E-50A main steam header upstream of the Main Steam Isolation Valve (MSIV). The steam supply valve receives an open signal from the Auxiliary Feedwater Actuation Signal (AFAS) instrumentation. The turbine driven AFW pump feeds both steam generators through the same flow paths as motor driven AFW pump P-8A.

One pump at full flow is sufficient to remove decay heat and cool the plant to Shutdown Cooling (SDC) System entry conditions.

The AFW System supplies feedwater to the steam generators during normal plant startup, shutdown, and hot standby conditions.

The AFW System is designed to supply sufficient water to the steam generators to remove decay heat with steam generator pressure at the setpoint of the MSSVs, with exception of AFW pump P-8C. If AFW pump P-8C is used, operator action may be required to either trip the four Primary Coolant Pumps (PCPs), start an additional AFW pump, or reduce steam generator pressure. This will allow the required flowrates to the steam generators that are assumed in the safety analyses. Subsequently, the AFW System supplies sufficient water to cool the plant to SDC entry conditions, and steam is released through the ADVs, or the turbine bypass valve if the condenser is available.

The AFW System actuates automatically on low steam generator level by an AFAS as described in LCO 3.3.3, "Engineered Safety Feature (ESF) Instrumentation" and 3.3.4, "ESF Logic." The AFAS initiates signals for starting the AFW pumps and repositioning the valves to initiate AFW flow to the steam generators. The actual pump starts are on an "as required" basis. P-8A is started initially, if the pump fails to start, or if the required flow is not established in a specified period of time, P-8C is started. If P-8A and P-8C do not start, or if required flow is not established in a specified period of time, then P-8B is started.

The AFW System is discussed in the FSAR, Section 9.7 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with a loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat, by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest MSSV set pressure plus 3% with the exception of AFW pump P-8C. If AFW pump P-8C is used, operator action may be required to either trip the four PCPs, start an additional AFW pump or reduce steam generator pressure. This will allow the required flowrate to the steam generators that are assumed in the safety analyses.

The limiting Design Basis Accident for the AFW System is a loss of normal feedwater.

In addition, the minimum available AFW flow and system characteristics impact the analysis of a small break loss of coolant accident.

The AFW System design is such that it can perform its function following loss of normal feedwater combined with a loss of offsite power with one AFW pump injecting AFW to one steam generator.

The AFW System satisfies Criterion 3 of 10 CFR 50.36(c)(2).

LCO

This LCO requires that two AFW trains be OPERABLE to ensure that the AFW System will perform the design safety function to mitigate the consequences of accidents that could result in overpressurization of the primary coolant pressure boundary. Three independent AFW pumps, in two diverse trains, ensure availability of residual heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two pumps from independent emergency buses. The third AFW pump is powered by a diverse means, a steam driven turbine supplied with steam from a source not isolated by the closure of the MSIVs.

BASES

LCO (continued)

The AFW System is considered to be OPERABLE when the components and flow paths required to provide AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to both steam generators. Prior to making the reactor critical during a plant startup, the turbine driven AFW pump shall be OPERABLE and capable of supplying AFW flow to both steam generators. When steam generator pressure is reduced, it is not required to have design inlet pressure available to the turbine driver in order to declare the turbine driven AFW pump OPERABLE. As steam generator pressure drops, the required AFW pump discharge head decreases accordingly. The reduced steam generator pressure available at lower temperatures in MODE 3 does not inhibit the turbine driven AFW pump's ability to feed the steam generator (Ref. 3). The piping, valves, instrumentation, and controls in the required flow paths shall also be OPERABLE.

The LCO is modified by three Notes. Note one indicates that only one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. This is because of reduced heat removal requirements, the short period of time in MODE 4 during which AFW is required, and the insufficient steam pressure available in MODE 4 to power the turbine driven AFW pump. Note two states that the turbine driven AFW pump is only required to be made OPERABLE prior to making the reactor critical. It is required to be OPERABLE during subsequent MODE 1, 2, and 3 operation. This allowance is needed to provide sufficient steam pressure to perform turbine and pump testing. Note three indicates that any two AFW pumps may be placed in manual mode for the purpose of testing, for not more than 4 hours. In this situation, the third AFW pump would still be available in the event of a plant transient. The two pumps that are in manual could be used at the discretion of the operator.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE and to function in the event that the main feedwater is lost. In addition, the AFW System is required to supply enough makeup water to replace steam generator secondary inventory, lost as the plant cools to MODE 4 conditions.

During heatup, the turbine driven AFW pump is only required to be made OPERABLE prior to making the reactor critical. It is required to be OPERABLE during subsequent MODE 1, 2, and 3 operation. This allowance is needed to provide sufficient steam pressure to perform turbine and pump testing.

BASES

APPLICABILITY (continued)

In MODE 4, the AFW System may be used for heat removal via the steam generator.

In MODES 5 and 6, the steam generators are not normally used for decay heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

Condition A is applicable whenever one or more AFW trains is inoperable, in MODE 1, 2, or 3. Action A.1 requires restoration of both trains to OPERABLE status within 72 hours. The 72 hour Completion Time is based on the assumption that at least 100% of the required AFW flow (that assumed in the safety analyses) is available to each steam generator. If the flow available to either steam generator is less than 100% of the required AFW flow, or if less than two AFW pumps are OPERABLE, Condition B must also be entered. In addition, if the combined flow available to both steam generators is less than 100% of the required AFW flow, Condition C must be entered as well.

Mechanical system LCOs typically provide a 72 hour Completion Time under conditions when a required system can perform its required safety function, but may not be able to do so assuming an additional failure. When operating in accordance with the Required Actions of an LCO Condition, it is not necessary to be able to cope with an additional single failure.

The AFW system can provide one hundred percent of the required AFW flow to each steam generator following the occurrence of any single active failure. Therefore, the AFW function can be met during conditions when those components which could be deactivated by a single active failure are known to be inoperable. Under that condition, however, the ability to provide the function after the occurrence of an additional failure cannot be guaranteed. Therefore, continued operation with one or more trains inoperable is allowed only for a limited time.

BASES

ACTIONS (continued)

B.1 and B.2

Condition B is applicable: 1) when the Required Actions of Condition A cannot be completed within the required Completion Time, 2) when the flow available to either steam generator is less than 100% of the required AFW flow, or 3) when less than two AFW pumps are OPERABLE. Condition A is applicable whenever one or more trains is inoperable. Therefore, when Condition B is applicable, Condition A is also applicable. (If the combined flow available to both steam generators is less than 100% of the required AFW flow, Condition C must be entered as well.) Being in Conditions A and B concurrently maintains both Completion Time clocks for instances where equipment repair allows exit from Condition B while the plant is still within the applicable conditions of the LCO.

Continued plant operation is not allowed if the available AFW flow to either steam generator is less than the required flow, because adequate AFW flow cannot be assured following a main steam line break affecting that steam generator (consider the case where the break occurs in the AFW piping). Therefore, if 1) the inoperable AFW trains cannot be restored to OPERABLE status within the required Completion Time of Condition A, or 2) the flow available to either steam generator is less than 100% of the required AFW flow, or 3) less than two AFW pumps are OPERABLE in MODES 1, 2, and 3, the plant must be placed in a MODE in which the LCO does not apply (except as noted in Condition C). To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1

Condition C is applicable if the combined flow available to both steam generators is less than 100% of the required AFW flow; Condition A is applicable whenever one or more trains is inoperable; and Condition B is applicable when the flow available to either steam generator is less than 100% of the required AFW flow, or when less than two AFW pumps are OPERABLE. Therefore, when Condition C is applicable, Conditions A and B are also applicable. Being in Conditions A, B, and C concurrently maintains the Completion Time clocks for instances where equipment repair allows exit from Condition C while the plant is still within the applicable conditions of the LCO.

One hundred percent AFW flow (that assumed in the safety analyses) can be provided by any one OPERABLE AFW pump and an OPERABLE flow path to each steam generator.

Required Action C.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until at least 100% of the required AFW flow is available. In this condition, there may be inadequate AFW flow available to remove decay heat and allow a stable plant shutdown.

With less than 100% of the required AFW flow available (ie. less than the AFW flow assumed in the safety analyses, while in MODES 1, 2, and 3, or less than the required AFW train OPERABLE while in MODE 4 with a steam generator relied upon for heat removal), the plant is in a seriously degraded Condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety grade equipment. In such a condition, the plant should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore at least 100% of the required AFW flow available. LCO 3.0.3 is not applicable, as it could force the plant into a less safe condition.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for the required manual, power operated, and automatic valves in the AFW water and steam supply flow path provides assurance that the proper flow paths exist for AFW operation. 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 manipulations; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

This test need not be performed for the steam driven AFW pump for MODE 4 operation.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.5.2

Verifying that each required AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of pump performance required by Section XI of the ASME 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.

This SR is modified by a Note indicating that this SR for the turbine driven AFW pump does not have to be met in MODE 3 when steam pressure is below 800 psig. This is because there is insufficient steam pressure and pump discharge pressure to allow the turbine driven pump to reach the normal test conditions.

Performance of inservice testing, discussed in the ASME Code, Section XI (Ref. 2), at 3 month intervals satisfies this requirement.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

This SR ensures that AFW can be delivered to the appropriate steam generator, in the event of any accident or transient that generates an AFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. Specific signals (e.g., AFAS) are tested under Section 3.3, "Instrumentation." This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note which states the SR is only required to be met in MODES 1, 2, and 3 when AFW is not in operation. With AFW in operation, the required trains are already aligned with the flow control valves in manual control.

SR 3.7.5.4

This SR ensures that the AFW pumps will start in the event of any accident or transient that generates an AFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. Specific signals (e.g., AFAS, handswitch) are tested under Section 3.3, "Instrumentation."

This test need not be performed for the steam driven AFW pump for MODE 4 operation.

The 18 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note. The Note states that the SR is only required to be met in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the autostart function is not required.

REFERENCES

1. FSAR, Section 9.7

2. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400.

3. Palisades Design Basis Document 1.03, Auxiliary Feedwater System, Section 3.4.1.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components, as well as the spent fuel pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System (SWS), and thus to the environment.

The isolation of the CCW to components or systems may render those components inoperable but does not affect the OPERABILITY of the CCW System.

The CCW System consists of three pumps connected in parallel to common suction and discharge headers. The discharge header splits into two parallel heat exchangers and then combines again into a common distribution header which supplies various heat loads. A common surge tank provides the necessary net positive suction head for the CCW pumps and a surge volume for the system. A train of CCW is considered to be that equipment electrically connected to a common safety bus necessary to transfer heat acquired from the various heat loads to the SWS. There are two CCW trains, each associated with a Safeguards Electrical Distribution Train which are described in Specification 3.8.9, "Distribution Systems - Operating."

1. The CCW train associated with the Left Safeguards Electrical Distribution Train consists of one CCW pump (P-52A), CCW heat exchanger E-54B, the CCW surge tank (T-3), associated piping, CCW control valves receiving an actuation signal from the left train (eg. CV-0911, CV-0938, & CV-0946), and controls for that equipment to perform their safety function.

2. The CCW train associated with the Right Safeguards Electrical Distribution Train consists of one CCW pump (P-52B), CCW heat exchanger E-54A, the CCW surge tank (T-3), associated piping, CCW control valves receiving an actuation signal from the right train (eg. CV-0937, CV-0940, & CV-0945), and controls for that equipment to perform their safety function.

BASES

BACKGROUND (continued)

3. The CCW system piping, CCW surge tank (T-3), CCW control valves which receive actuation signals from both right and left trains (eg. CV-0910, CV-0913, CV-0944, CV-0944A, CV-0950, & CV-0977B), and controls for that equipment to perform their safety function.

CCW system components receive three automatic actuation signals, a Safety Injection Signal (SIS), a Recirculation Actuation Signal (RAS), or a Containment High Pressure (CHP) signal:

1. SIS starts the CCW pumps, isolates non-essential CCW loads outside the containment, opens the CCW inlet valves to the Shutdown Heat Exchangers (SDHXs), and sends an open signal to the engineered safeguards pump cooler CCW inlet valves (which are normally open).
2. RAS sends an open signal to the CCW heat exchanger CCW inlet valves (which are normally open).
3. CHP isolates the CCW loads inside the containment.

The CCW System cools three groups of loads which are described in the FSAR (Ref. 1). The major loads are:

1. Safety related loads outside the containment,
   Shutdown Cooling Heat Exchangers
   Engineered Safeguards Pump Coolers

2. Non-safety related loads outside the Containment, and
   Spent Fuel Cooling Heat Exchangers
   Waste Gas Compressors
   Rad Waste Evaporators
   Charging Pump Oil Coolers

3. Non-safety related loads inside the Containment.
   Letdown Heat Exchanger
   Shield Cooling Heat Exchangers
   Primary Coolant Pump Leakoff and Oil Coolers
   CRDM Seal Coolers

Each of these groups of loads can be cooled by the flow from one CCW pump. During normal operation, when full flow is not being provided to the Shutdown Cooling and Letdown Heat Exchangers, one CCW pump can provide the required flow for all three groups of loads. Two pumps may be operated to provide additional system flow and thermal stability.

BASES

BACKGROUND (continued)

During post accident conditions, with all CCW and related system components OPERABLE, one hundred percent of the required CCW post accident cooling capability can be provided by any one CCW pump with sufficient flow margin to allow manually restoring CCW flow to the Spent Fuel Pool Cooling Heat Exchangers. If CCW or related systems have components out of service, additional CCW pumps may be required to provide the required post accident cooling capability.

For post accident cooling, the Engineered Safety Features signals reposition several valves to maximize containment cooling and conserve CCW flow. Initially, a safety injection signal will start the CCW pumps, and open the large CCW inlet valves to the Shutdown Cooling Heat Exchangers (CCW cools the Shutdown Cooling Heat Exchangers, which cool the containment spray flow). A safety injection signal will also isolate the non-safety related CCW loads outside the containment. A Containment High Pressure signal will isolate the non-safety related CCW loads inside the containment. The occurrence of these automatic actions will provide the required CCW post accident cooling capability while limiting the CCW flow requirement to that which can be provided by one CCW pump.

The safety analyses assume that both CCW heat exchangers are available. To assure that both heat exchangers will be available even with a single active failure, the CCW inlet valves to the CCW heat exchangers are maintained in the full open position during plant operation.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.3 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Shutdown Cooling (SDC) System heat exchangers. This may utilize the SDC heat exchangers during a normal or post accident cooldown and shutdown in conjunction with the Containment Spray System during the recirculation phase following a LOCA.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW train in conjunction with the SWS and a 100% capacity Containment Cooling System (containment spray, containment coolers, or a combination) removing core decay heat between 20 to 40 minutes after a design basis LOCA. 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 Primary Coolant System (PCS) by the safety injection pumps. Any single CCW pump can provide one hundred percent of the required CCW post accident cooling capability if both CCW heat exchangers are available.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power. The CCW System also functions to cool the plant from SDC entry conditions (T_{ave} < 300°F) to MODE 5 (T_{ave} < 200°F) during normal and post accident operations. The time required to cool from 300°F to 200°F is a function of the number of CCW and SDC trains operating. This assumes that the maximum Lake Michigan water temperature of LCO 3.7.9, "Ultimate Heat Sink (UHS)," occurs simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2).

BASES

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies. 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 CCW trains must be OPERABLE. At least one CCW train will operate assuming the worst single active failure occurs coincident with the loss of offsite power.

The CCW train associated with the Left Safeguards Electrical Distribution Train is considered OPERABLE when:

a. CCW pump P-52A is OPERABLE;

b. CCW surge tank T-3 and other common components are OPERABLE;

c. CCW heat exchanger E-54B is OPERABLE; and

d. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The CCW train associated with the Right Safeguards Electrical Distribution Train is considered OPERABLE when:

a. CCW pump P-52B is OPERABLE;

b. CCW surge tank T-3 and other common components are OPERABLE;

c. CCW heat exchanger E-54A is OPERABLE; and

d. The associated piping, valves, 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 that must be prepared to perform its post accident safety functions, primarily PCS heat removal by cooling the SDC heat exchanger.

In MODES 5 and 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Condition A is applicable whenever one or more CCW trains is inoperable. Action A.1 requires restoration of both trains to OPERABLE status within 72 hours. The 72 hour Completion Time is based on the assumption that at least 100% of the required CCW post accident cooling capability (that assumed in the safety analyses) is available. (If, however, less than 100% of the CCW post accident cooling is available, Condition C must also be entered.)

Mechanical system LCOs typically provide a 72 hour Completion Time under conditions when a required system can perform its required safety function, but may not be able to do so assuming an additional failure. When operating in accordance with the Required Actions of an LCO Condition, it is not necessary to be able to cope with an additional single failure.

The CCW system can provide one hundred percent of the required post accident cooling capability following the occurrence of any single active failure. Therefore, the CCW function can be met during conditions when those components which could be deactivated by a single active failure are known to be inoperable. Under that condition, however, the ability to provide the function after the occurrence of an additional failure cannot be guaranteed. Therefore, continued operation with one or more trains inoperable is allowed only for a limited time.

B.1 and B.2

Condition B is applicable when the Required Actions of Condition A cannot be completed within the required Completion Time. Condition A is applicable whenever one or more trains is inoperable. Therefore, when Condition B is applicable, Condition A is also applicable. (If less than 100% of the post accident CCW cooling capability is available, Condition C must be entered as well.) Being in Conditions A and B concurrently maintains both Completion Time clocks for instances where equipment repair allows exit from Condition B while the plant is still within the applicable conditions of the LCO.

BASES

ACTIONS

B.1 & B.2 (continued)

If the required CCW trains cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

C.1

Condition C is applicable with one or more trains inoperable when there is less than 100% of the required CCW post accident cooling capability available. Condition A is applicable whenever one or more trains is inoperable. Therefore, when this Condition is applicable, Condition A is also applicable. Being in Conditions A and C concurrently maintains both Completion Time clocks for instances where equipment repair restores 100% of the required CCW post accident cooling capability while the LCO is still applicable, allowing exit from Condition C (and LCO 3.0.3).

If the CCW side (shell side) of either CCW heat exchanger is out of service, 100% of the required CCW post accident cooling capability cannot be assured. If the SWS side (tube side) of either CCW heat exchanger is out of service, 100% of the required CCW post accident cooling capability can be provided, if other equipment outages are limited. One hundred percent of the post accident CCW cooling can be provided with the SWS side of one CCW heat exchanger out of service if the following equipment is OPERABLE: 3 safety related Containment Air Coolers, 2 Containment Spray Pumps, CCW pumps P-52A and P-52B, 2 SWS pumps, and both Shutdown Cooling Heat Exchangers, and if

1. One CCW Containment header valve, CV-0910, CV-0911, or CV-0940, is OPERABLE, and
2. Two CCW isolation valves for the non-safety related loads outside the containment, CV-0944A and CV-0944 (or CV-0977B), are OPERABLE.

One hundred percent of the required CCW post accident cooling can be provided despite the inoperability of one or more of those CCW valves closed by Safety Injection, which isolate cooling to non-essential loads, provided there are sufficient CCW pumps available to supply the additional flow.

BASES

ACTIONS

C.1 (continued)

One hundred percent of the required CCW post accident cooling capability can be provided by one CCW pump if both CCW heat exchangers are available and if:

1. One CCW Containment header valve, CV-0910, CV-0911, or CV-0940, is OPERABLE, and

2. Two CCW isolation valves for the non-safety related loads outside the containment, CV-0944A and CV-0944 (or CV-0977B), are OPERABLE.

One hundred percent of the required CCW post accident cooling capability can be provided by two CCW pumps if both CCW heat exchangers are available and if:

1. One CCW Containment header valve, CV-0910, CV-0911, or CV-0940, is OPERABLE, or

2. Two CCW isolation valves for the non-safety related loads outside the containment, CV-0944A and CV-0944 (or CV-0977B), are OPERABLE.

With less than 100% of the required CCW post accident cooling capability available, the plant is in a condition outside the assumptions of the safety analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since 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 potentially being mispositioned are in their correct position.

This SR is modified by a Note indicating that the isolation of the CCW to components or systems may render those components inoperable but does not affect the OPERABILITY of the CCW System.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1 (continued)

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation signal. Specific signals (e.g., safety injection, RAS) are tested under Section 3.3, "Instrumentation." This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, and 3. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal in the "with standby power available" mode which tests the starting of the pumps by the SIS-X relays. The starting of the pumps by the sequencer is performed in Section 3.8, "Electrical Power Systems." This SR is modified by a Note which states this SR is only required to be met in MODES 1, 2, and 3. The instrumentation providing the input signal is not required in MODE 4, therefore, to keep consistency with Section 3.3, "Instrumentation," the SR is not required to be met in this MODE. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 9.3

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The plant Class 1E Electrical Power Distribution System AC sources consist of the offsite power sources, and the onsite standby power sources, Diesel Generators 1-1 and 1-2 (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 AC power system at Palisades consists of a 345 kV switchyard, three circuits connecting the plant with off-site power (station power, startup, and safeguards transformers), the on-site distribution system, and two DGs. The on-site distribution system is divided into safety related (Class 1-E) and non-safety related portions.

The switchyard interconnects six transmission lines from the off-site transmission system, the output line from the Covert Generating Station, and the output line from the Palisades main generator. These lines are connected in a "breaker and a half" scheme between the Front (F) and Rear (R) buses such that any single off-site line may supply the Palisades station loads when the plant is shutdown.

Two circuits supplying Palisades 2400 V buses from off-site are fed directly from a switchyard bus through the startup and safeguards transformers. They are available both during operation and during shutdown. The third circuit supplies the plant loads by "back feeding" through the main generator output circuit and station power transformers after the generator has been disconnected by a motor operated disconnect.

The station power transformers are connected into the main generator output circuit. Station power transformers 1-1 and 1-2 connect to the generator 22 kV output bus. Station power transformer 1-3 connects to the generator output line on the high voltage side of the main transformer. Station power transformers 1-1 and 1-3 supply non-safety related 4160 V loads during plant power operation and during backfeeding operations. Station power transformer 1-2 can supply both safety related and non-safety related 2400 V loads during plant power operation or backfeeding operation.

BASES

BACKGROUND (continued)

The three startup transformers are connected to a common 345 kV overhead line from the switchyard R bus. Startup transformers 1-1 and 1-3 supply 4160 V non-safety related station loads; Startup Transformer 1-2 can supply both safety related and non-safety related 2400 V loads. The startup transformers are available during operation and shutdown.

Safeguards Transformer 1-1 is connected to the switchyard F bus. It feeds station 2400 V loads through an underground line. It is available to supply these loads during operation and shutdown.

The onsite distribution system consists of seven main distribution buses (4160 V buses 1A, 1B, 1F, and 1G, and 2400 V buses 1C, 1D, and 1E) and supported lower voltage buses, Motor Control Centers (MCCs), and lighting panels. The 4160 V buses and 2400 V bus 1E are not safety related. Buses 1C and 1D and their supported buses and MCCs form two independent, redundant, safety related distribution trains. Each distribution train supplies one train of engineered safety features equipment.

In the event of a generator trip, all loads supplied by the station power transformers are automatically transferred to the startup transformers. Loads supplied by the safeguards transformer are unaffected by a plant trip. If power is lost to the safeguards transformer, the 2400 V loads will automatically transfer to startup transformer 1-2. If the startup transformers are not energized when these transfers occur, their output breakers will be blocked from closing and the 2400 V safety related buses will be energized by the DGs.

The two DGs each supply one 2400 V bus. They provide backup power in the event of loss of off-site power, or loss of power to the associated 2400 V bus. The continuous rating of the DGs is 2500 kW, with 110 percent overload permissible for 2 hours. The required fuel in the Fuel Oil Storage Tank and DG Day Tank will supply one DG for a minimum period of 7 days assuming accident loading conditions and fuel conservation practices.

If either 2400 V bus, 1C or 1D, experiences a sustained undervoltage, the associated DG is started, the affected bus is separated from its offsite power sources, major loads are stripped from that bus and its supported buses, the DGs are connected to the bus, and ECCS or shutdown loads are started by an automatic load sequencer.

BASES

BACKGROUND (continued)

The DGs share a common fuel oil storage and transfer system. A single buried Fuel Oil Storage Tank is used, along with an individual day tank for each DG, to maintain the required fuel oil inventory. Two fuel transfer pumps are provided. The fuel transfer pumps are necessary for long-term operation of the DGs. Testing has shown that each DG consumes about 2.6 gallons of fuel oil per minute at 2400 kW. Each day tank is required to contain at least 2500 gallons. Therefore, each fuel oil day tank contains sufficient fuel for more than 15 hours of full load (2500 kW) operation. Beyond that time, a fuel transfer pump is required for continued DG operation.

Either fuel transfer pump is capable of supplying either DG. However, each fuel transfer pump is not capable, with normally available switching, of being powered from either DG. DG 1-1 can power either fuel transfer pump, but DG 1-2 can only power P-18A. The fuel oil pumps share a common fuel oil storage tank, and common piping.

Fuel transfer pump P-18A is powered from MCC-8, which is normally connected to Bus 1D (DG 1-2) through Station Power Transformer 12 and Load Center 12. In an emergency, P-18A can be powered from Bus 1C (DG 1-1) by cross-connecting Load Centers 11 and 12.

Fuel transfer pump P-18B is powered from MCC-1, which is normally connected to Bus 1C (DG 1-1) through Station Power Transformer 19 and Load Center 19. P-18B cannot be powered, using installed equipment, from Bus 1D (DG 1-2).

APPLICABLE SAFETY ANALYSES

The safety analyses do not explicitly address AC electrical power. They do, however, assume that the Engineered Safety Features (ESF) are available. The OPERABILITY of the ESF functions is supported by the AC Power Sources.

The design requirements are for each assumed safety function to be available under the following conditions:

a. The occurrence of an accident or transient,

b. The resultant consequential failures,

c. A worst-case single active failure,

d. Loss of all offsite or all onsite AC power, and

e. The most reactive control rod fails to insert.

APPLICABLE SAFETY ANALYSES (continued)

One proposed mechanism for the loss of off-site power is a perturbation of the transmission grid because of the loss of the plant's generating capacity. A loss of off-site power as a result of a generator trip can only occur during MODE 1 with the generator connected to the grid. However, it is also assumed in analysis for some events in MODE 2, such as a control rod ejection. No specific mechanism for initiating a loss of off-site power when the plant is not on the line is discussed in the FSAR.

In most cases, it is conservative to assume that off-site power is lost concurrent with the accident and that the single failure is that of a DG. That would leave only one train of safeguards equipment to cope with the accident, the other being disabled by the loss of AC power. Those analyses which assume that a loss of off-site power and failure of a single DG accompany the accident assume 11 seconds from the loss of power until the bus is re-energized. This time includes time for all portions of the circuitry necessary for detecting the undervoltage (relays and auxiliary relays) and starting the DG. Included in the 11 seconds, the analyses also assume 10 seconds for the DG to start and connect to the bus, and additional time for the sequencer to start each safeguards load.

The same assumptions are not conservative for all accident analyses. When analyzing the effects of a steam or feed line break, the loss of the condensate and feedwater pumps would reduce the steam generator inventory, so a loss of off-site power is not assumed.

In MODE 5 and MODE 6, loss of off-site power can be considered as an initiating event for a loss of shutdown cooling event.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and an independent DG for each safeguards 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 or a postulated DBA.

LCO (continued)

General Design Criterion 17 (Ref. 1) requires, in part, that: "Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions."

The qualified offsite circuits available are Safeguards Transformer 1-1 and Startup Transformer 1-2. Station Power Transformer 1-2 is not qualified as a required source for LCO 3.8.1 since it is not independent of the other two offsite circuits. This LCO does not prohibit use of Station Power Transformer to power the 2400 V safety related buses, but the two qualified sources must be OPERABLE.

Each offsite circuit must be capable of maintaining acceptable frequency and voltage, and accepting required loads during an accident, while supplying the 2400 V safety related buses.

Following a loss of offsite power, each DG must be capable of starting and connecting to its respective 2400 V bus. This will be accomplished within 10 seconds after receipt of a DG start signal. 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 2400 V safety related buses.

Proper sequencing of loads and tripping of nonessential loads are required functions for DG OPERABILITY.

APPLICABILITY

The AC sources are required to be OPERABLE above MODE 5 to ensure that redundant sources of off-site and on-site AC power are available to support engineered safeguards equipment in the event of an accident or transient. The AC sources also support the equipment necessary for power operation, plant heatups and cooldowns, and shutdown operation.

The AC source requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in LCO 3.8.2, "AC Sources - Shutdown."

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with the 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 failure to meet this Required Action. 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.

As stated in SR 3.0.2, the 25% extension allowed by SR 3.0.2 may be applied to Required Actions whose Completion Time is stated as "once per . . ." however, the 25% extension does not apply to the initial performance of a Required Action with a periodic Completion Time that requires performance on a "once per . . ." basis. The 25% extension applies to each performance of the Required Action after the initial performance. Therefore, while Required Action 3.8.1 A.1 must be initially performed within 1 hour without any SR 3.0.2 extension, subsequent performances at the "Once per 8 hours" interval may utilize the 25% SR 3.0.2 extension.

A.2

According to the recommendations of Regulatory Guide (RG) 1.93 (Ref. 2), 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 plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

ACTIONS

A.2 (continued)

The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single continuous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 17 days) allowed prior to complete restoration of the LCO. The 10-day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 10 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the Completion Time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

ACTIONS (continued)

B.2

In accordance with LCO 3.0.6, the requirement to declare required features inoperable carries with it the requirement to take those actions required by the LCO for that required equipment.

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features within a train redundant to the train that has an inoperable DG. If the train that has an inoperable DG contains multiple features redundant to the inoperable feature in the other train, all those multiple features must be declared inoperable. For example, if DG 1-1 and Containment Spray Pump P-54A are inoperable concurrently, Containment Spray Pumps P-54B and P-54C must both be declared inoperable. In this example, if off-site power were lost, neither P-54B nor P-54C would be available.

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 Completion Time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required supporting or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for Required Action B.2. Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost.

ACTIONS

B.2 (continued)

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 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 (test starting of the OPERABLE DG) does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed to not exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing Required Action B.3.1 or B.3.2 the corrective action system would normally 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. 3), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

ACTIONS (continued)

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System for a limited period. The 7-day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10-day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 10 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

ACTIONS (continued)

C.1

In accordance with LCO 3.0.6 the requirement to declare required features inoperable carries with it the requirement to take those actions required by the LCO for that required equipment.

Required Action C.1, which applies when two required 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. The rationale for the reduction to 12 hours is that RG 1.93 (Ref. 2) recommends a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains.

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 Completion 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.

ACTIONS (continued)

C.2

According to the recommendations of RG 1.93 (Ref. 2), 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 accomplish 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.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the plant 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.

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 the requirements for the loss of one offsite circuit and one DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. The 12-hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

According to the recommendations of RG 1.93 (Ref. 2), operation may continue in Condition D for a period that should not exceed 12 hours.

ACTIONS (continued)

E.1

With both DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, no AC source would be available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a 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 an inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to the recommendations of RG 1.93 (Ref. 2), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 4). 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 RG 1.9 (Ref. 5) and RG 1.137 (Ref. 6).

Where the SRs discussed herein specify voltage and frequency tolerances for the DGs operated in the "Unit" mode, the following is applicable. The minimum steady state output voltage of 2280 V is 95% of the nominal 2400 V generator rating. This value is above the setting of the primary undervoltage relays (127-1 and 127-2) and above the minimum analyzed acceptable bus voltage. It also allows for voltage drops to motors and other equipment down through the 120 V level. The specified maximum steady state output voltage of 2520 V is 105% of the nominal generator rating of 2400 V. It is below the maximum voltage rating of the safeguards motors, 2530 V. The specified minimum and maximum frequencies of the DG are 59.5 Hz and 61.2 Hz, respectively. The minimum value assures that ESF pumps provide sufficient flow to meet the accident analyses. The maximum value is equal to 102% of the 60 Hz nominal frequency and is derived from the recommendations given in RG 1.9 (Ref. 5).

Higher maximum tolerances are specified for final steady state voltage and frequency following a loss of load test, because that test must be performed with the DG controls in the "Parallel" mode. Since "Parallel" mode operation introduces both voltage and speed droop, the DG final conditions will not return to the nominal "Unit" mode settings.

SR 3.8.1.1

This SR assures that the required offsite circuits are OPERABLE. Each offsite circuit must be energized from associated switchyard bus through its disconnect switch to be OPERABLE.

Since each required offsite circuit transformer has only one possible source of power, the associated switchyard bus, and since loss of voltage to either the switchyard bus or the transformer is alarmed in the control room, correct alignment and voltage may be verified by the absence of these alarms.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

The 7 day Frequency is adequate because disconnect switch positions cannot change without operator action and because their status is displayed in the control room.

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the plant in a safe shutdown condition.

The monthly test starting of the DG provides assurance that the DG would start and be ready for loading in the time period assumed in the safety analyses. The monthly test, however does not, and is not intended to, test all portions of the circuitry necessary for automatic starting and loading. The operation of the bus undervoltage relays and their auxiliary relays which initiate DG starting, the control relay, which initiates DG breaker closure, and the DG breaker closure itself are not verified by this test. Verification of automatic operation of these components requires de-energizing the associated 2400 V bus and cannot be done during plant operation. For this test, the 10-second timing is started when the DG receives a start signal, and ends when the DG voltage sensing relays actuate. For the purposes of SR 3.8.1.2, the DGs are manually started from standby conditions. Standby conditions for a DG mean the diesel engine is not running, its coolant and oil temperatures are being maintained consistent with manufacturer recommendations, and ≥ 20 minutes have elapsed since the last DG air roll.

Three relays sense the terminal voltage on each DG. These relays, in conjunction with a load shedding relay actuated by bus undervoltage, initiate automatic closing of the DG breaker. During monthly testing, the actuation of the three voltage sensing relays is used as the timing point to determine when the DG is ready for loading.

The 31-day Frequency for performance of SR 3.8.1.2 agrees with the original licensing basis for the Palisades plant.

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 greater than or equal to the equivalent of the maximum expected accident loads for at least 15 minutes. A minimum total run time of 60 minutes is required to stabilize engine temperatures.

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because there are no provisions to automatically shift the DG controls from parallel mode to unit mode. Additionally, when paralleled, there are certain conditions where the protection schemes may not prevent DG overloading and subsequent breaker trip and lockout.

The 31-day Frequency for this Surveillance is consistent with the original Palisades licensing basis.

The SR is modified by three Notes. Note 1 states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated. Note 2 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 3 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The specified level is adequate for a minimum of 15 hours of DG operation at full load.

The 31-day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low-level alarms are provided and plant operators would be aware of any uses of the DG during this period.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5

Each DG is provided with an engine overspeed trip to prevent damage to the engine. The loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. This Surveillance may be accomplished with the DG in the "Parallel" mode.

An acceptable method is to parallel the DG with the grid and load the DG to a load equal to or greater than its single largest post-accident load. The DG breaker is tripped while its voltage and frequency (or speed) are being recorded. The time, voltage, and frequency tolerances specified in this SR are derived from the recommendations of RG 1.9, Revision 3 (Ref. 5).

RG 1.9 (Ref. 5) recommends that the increase in diesel speed during the transient does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. The Palisades DGs have a synchronous speed of 900 rpm and an overspeed trip setting range of 1060 to 1105 rpm. Therefore, the maximum acceptable transient frequency for this SR is 68 Hz.

The minimum steady state voltage is specified to provide adequate margin for the switchgear and for both the 2400 and 480 V safeguards motors; the maximum steady state voltage is 2400 +10% V as recommended by RG 1.9 (Ref. 5).

The minimum acceptable frequency is specified to assure that the safeguards pumps powered from the DG would supply adequate flow to meet the safety analyses. The maximum acceptable steady state frequency is slightly higher than the +2% (61.2 Hz) recommended by RG 1.9 (Ref. 5) because the test must be performed with the DG controls in the Parallel mode. The increased frequency allowance of 0.3 Hz is based on the expected speed differential associated with performance of the test while in the "Parallel" mode.

The 18-month surveillance Frequency is consistent with the recommendation of RG 1.9 (Ref. 5).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine and generator load response under a complete loss of load. These acceptance criteria provide DG damage protection. The 4000 V limitation is based on generator rating of 2400/4160V and the ratings of those components (connecting cables and switchgear) that would experience the voltage transient. While the DG is not expected to experience this transient during an event and continue to be available, this response ensures that the DG is not degraded for future application, including re-connection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, yet still provide adequate testing margin between the specified power factor limit and the DG design power factor limit of 0.8, testing must be performed using a power factor ≤ 0.9. This is consistent with RG 1.9 (Ref. 5).

The 18-month Frequency is consistent with the recommendation of RG 1.9 (Ref. 5) and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.7

As recommended by RG 1.9 (Ref. 5) 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 re-energizing of the emergency buses and respective loads from the DG.

The requirement to energize permanently connected loads is met when the DG breaker closes, energizing its associated 2400 V bus. Permanently connected loads are those that are not disconnected from the bus by load shedding relays. They are energized when the DG breaker closes. It is not necessary to monitor each permanently connected load.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

The DG auto-start and breaker closure time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. For this test, the 10-second timing is started when the DG receives a start signal, and ends when the DG breaker closes. The safety analyses assume 11 seconds from the loss of power until the bus is re-energized.

The requirement to verify that auto-connected shutdown loads are energized refers to those loads that are actuated by the Normal Shutdown Sequencer. Each load should be started to assure that the DG is capable of accelerating these loads at the intervals programmed for the Normal Shutdown Sequence. The sequenced pumps may be operating on recirculation flow.

The requirements to maintain steady state voltage and frequency apply to the "steady state" period after all sequenced loads have been started. This period need only be long enough to achieve and measure steady voltage and frequency.

The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to supply permanently connected loads for ≥ 5 minutes, refers to the duration of the DG connection to the associated safeguards bus. It is not intended to require that sequenced loads be operated throughout the 5-minute period. It is not necessary to monitor each permanently connected load.

The requirement to verify the connection and supply of permanently and automatically connected loads is intended to demonstrate the DG loading logic. This testing may be accomplished in any series of sequential, overlapping, or total steps so that the required connection and loading sequence is verified.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 5).

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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

RG 1.9 (Ref. 5) recommends 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, ≥ 120 minutes of which is at a load above its analyzed peak accident loading and the remainder of the time at a load equivalent to the continuous duty rating of the DG. SR 3.8.1.8 only requires ≥ 100 minutes at a load above the DG analyzed peak accident loading. The 100 minutes required by the SR satisfies the intent of the recommendations of the RG, but allows some tolerance between the time requirement and the DG rating. Without this tolerance, the load would have to be reduced at precisely 2 hours to satisfy the SR without exceeding the manufacturer's rating of the DG.

The DG starts for this Surveillance can be performed either from standby or hot conditions.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, yet still provide adequate testing margin between the specified power factor limit and the DG design power factor limit of 0.8, testing must be performed using a power factor of ≤ 0.9. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

In addition, a Note to the SR states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated.

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because there are no provisions to automatically shift the DG controls from parallel mode to unit mode. Additionally, when paralleled, there are certain conditions where the protection schemes may not prevent DG overloading and subsequent breaker trip and lockout.

The 18-month Frequency is consistent with the recommendations of RG 1.9 (Ref. 5).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

As recommended by RG 1.9 (Ref. 5), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready to load status when offsite power is restored. The test is performed while the DG is supplying its associated 2400 V bus, but not necessarily carrying the sequenced accident loads. 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, the automatic load sequencer is reset, and the DG controls are returned to "Unit."

During the period when the DG is paralleled to the grid, it must be considered inoperable. This is because there are no provisions to automatically shift the DG controls from parallel mode to unit mode. Additionally, when paralleled, there are certain conditions where the protection schemes may not prevent DG overloading and subsequent breaker trip and lockout.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 5).

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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

If power is lost to bus 1C or 1D, 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 by concurrent motor starting currents. The 0.3-second load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and ensures that safety analysis assumptions regarding ESF equipment time delays are met. Logic Drawing E-17 Sheet 4 (Ref. 7) provides a summary of the automatic loading of safety related buses.

The Frequency of 18 months is consistent with the recommendations of RG 1.9 (Ref. 5), takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.11

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, PCS, and containment design limits are not exceeded.

The requirement to energize permanently connected loads is met when the DG breaker closes, energizing its associated 2400 V bus. Permanently connected loads are those that are not disconnected from the bus by load shedding relays. They are energized when the DG breaker closes. It is not necessary to monitor each permanently connected load. The DG auto-start and breaker closure time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. For this test, the 10-second timing is started when the DG receives a start signal, and ends when the DG breaker closes. The safety analyses assume 11 seconds from the loss of power until the bus is re-energized.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

In addition, a Note to the SR states that momentary transients outside the required band do not invalidate this test. This is to assure that a minor change in grid conditions and the resultant change in DG load, or a similar event, does not result in a surveillance being unnecessarily repeated.

The requirement to verify that auto-connected shutdown loads are energized refers to those loads that are actuated by the DBA Sequencer. Each load should be started to assure that the DG is capable of accelerating these loads at the intervals programmed for the DBA Sequence. Since the containment spray pumps do not actuate on SIS generated by Pressure Low Pressure, the test should be performed such that spray pump starting by the sequencer is also verified along with the other SIS loads. The sequenced pumps may be operating on recirculation flow or in other testing modes. The requirements to maintain steady state voltage and frequency apply to the "steady state" period after all sequenced loads have been started. This period need only be long enough to achieve and measure steady voltage and frequency.

The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to supply permanently connected loads for ≥ 5 minutes, refers to the duration of the DG connection to the associated 2400 V bus. It is not intended to require that sequenced loads be operated throughout the 5-minute period. It is not necessary to monitor each permanently connected load.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

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.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17
2. Regulatory Guide 1.93, December 1974
3. Generic Letter 84-15, July 2, 1984
4. 10 CFR 50, Appendix A, GDC 18
5. Regulatory Guide 1.9, Rev. 3, July 1993
6. Regulatory Guide 1.137, Rev. 1, October 1979
7. Palisades Logic Drawing E-17, Sheet 4