Nebraska Public Power District
Nebraska's Energy Leader

NLS2002087

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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Subject: Technical Specification Bases Changes
Cooper Nuclear Station
NRC Docket No. 50-298, DPR-46

In accordance with the requirements of Cooper Nuclear Station Technical Specification 5.5.10.d and 10 CFR 50.71(e), enclosed are changes to the Technical Specification Bases implemented without prior Nuclear Regulatory Commission approval for the current reporting period of August 7, 2000 to June 21, 2002, inclusive.

If you have any questions regarding this submittal, please contact Mr. Paul Fleming at 402-825-2774.

M. T. Coyle
Site Vice President

/nr
Enclosure

cc: Regional Administrator, w/enclosure
USNRC - Region IV

Senior Project Manager, w/enclosure
USNRC - NRR Project Directorate IV-1

Senior Resident Inspector, w/enclosure
USNRC

NPG Distribution, w/o enclosure

Records, w/enclosure

A001

Cooper Nuclear Station
P.O. Box 98 / Brownville, NE 68321-0098
***Telephone:** (402) 825-3811 / **Fax:** (402) 825-5211*
http://www.nppd.com

Correspondence Number: NLS2002087

The following table identifies those actions committed to by Nebraska Public Power District (NPPD) in this document. Any other actions discussed in the submittal represent intended or planned actions by NPPD. They are described for information only and are not regulatory commitments. Please notify the NL&S Manager at Cooper Nuclear Station of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	COMMITTED DATE OR OUTAGE
None	

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High (Startup) (continued)

The APRM System is divided into two groups of channels with three APRM channel inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux-High (Startup) with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The Average Power Range Monitor Neutron Flux-High (Startup) Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists.

In MODE 1, the Average Power Range Monitor Neutron Flux-High (Fixed) Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events. Function 2.a is bypassed when the reactor mode switch is in run.

2.b. Average Power Range Monitor Neutron Flux-High (Flow Biased)

The Average Power Range Monitor Neutron Flux-High (Flow Biased) Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern. The Average Power Range Monitor Neutron Flux-High (Flow Biased) Function is not specifically credited in the safety analyses, but is intended to provide protection against transients where THERMAL POWER increases slowly, and to provide protection for power oscillations which may result from reactor thermal hydraulic instability.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Neutron Flux-High (Flow Biased) (continued)

The APRM System is divided into two groups of channels with three APRM Channel inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux-High (Flow Biased) with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM channel receives a flow signal representative of total recirculation loop flow. The total recirculation loop drive flow signals are generated by two flow units, one of which supplies signals to the trip system A APRMs, while the other supplies signals to the trip system B APRMs. Each flow unit signal is provided by summing up the flow signals from the two recirculation loops. The instrumentation is an analog type with redundant flow signals that can be compared. Each required Average Power Range Monitor Neutron Flux-High (Flow Biased) channel requires an input from one OPERABLE flow unit. If a flow unit is inoperable, the associated Average Power Range Monitor Neutron Flux-High (Flow Biased) channels must be considered inoperable.

The terms for the Allowable Value of the APRM Neutron Flux-High (Flow Biased) trip are defined as follows: S is the setting in percent rated power; W is the two loop recirculation flow rate in percent rated flow (rated loop recirculation flow rate is that recirculation flow rate which provides 100% core flow at 100% power); ΔW is the difference between two loop and single loop effective drive flow at the same core flow. ΔW equals zero for two recirculation loop operation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Neutron Flux-High (Flow Biased) (continued)

The Average Power Range Monitor Neutron Flux-High (Flow Biased) Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor Neutron Flux-High (Fixed)

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Neutron Flux-High (Fixed) Function is capable of generating a trip signal to prevent fuel damage or excessive Reactor Coolant System (RCS) pressure. For the overpressurization protection analysis of Reference 6, the Average Power Range Monitor Neutron Flux-High (Fixed) Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (SRVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 7) takes credit for the Average Power Range Monitor Neutron Flux-High (Fixed) Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux-High (Fixed) with two channels in each trip system arranged in a one-out-of-

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Drywell Pressure-High

High pressure in the drywell could indicate a break in the RCPB. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the drywell. The Drywell Pressure-High Function is assumed to scram the reactor during large and intermediate break LOCAs inside primary containment. The reactor scram reduces the amount of energy required to be absorbed and along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure switches that sense drywell pressure. The Allowable Value was selected to be as low as possible and indicative of a LOCA inside primary containment.

Four channels of Drywell Pressure-High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

7a, 7b. Scram Discharge Volume Water Level-High

The north and south SDVs are independent with separate drain lines and isolation valves. Each SDV is a separate RPS Function, each Function consisting of both type 7.a and 7.b channels. Each SDV accommodates approximately half of the water displaced by the motion of the CRD pistons during a reactor scram. Should either SDV fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated while the remaining free volumes are still sufficient to accommodate the water from a full core scram. No credit is taken for a scram initiated from these Functions for any of the design basis accidents or transients analyzed in the USAR. However, they are retained to ensure the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two differential pressure transmitters for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a differential pressure transmitter to each RPS trip

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

system from each SDV. The level measurement instrumentation satisfies the recommendations of Reference 9.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in each SDV to accommodate the water from a full scram.

For each Scram Discharge Volume Water Level-High Function (i.e., for each SDV), there is one channel of each type (type 7.a and 7.b) in each trip system. Since Table 3.3.1.1-1 provides the total number of required channels per trip system for both SDVs, a total of two required channels of each type per trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve-Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve-Closure Function is the primary scram signal for the turbine trip, feedwater controller failure maximum demand, and the loss of main condenser vacuum events analyzed in Reference 2. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Stop Valve-Closure signals are initiated from position switches located on each of the two TSVs. Two independent position switches are associated with each stop valve. One of the two switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from two Turbine Stop Valve-Closure channels, each consisting of one position switch assembly with two contacts, each inputting to a relay. The relays provide a parallel logic input to an RPS trip logic channel. The logic for the Turbine Stop Valve-Closure Function is such that both TSVs must be closed to produce a scram. Single valve closure will produce a half scram. This Function must be enabled at THERMAL POWER $\geq$ 30% RTP as measured by

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

turbine first stage pressure. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

The Turbine Stop Valve-Closure Allowable Value is selected to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Four channels of Turbine Stop Valve-Closure Function, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if both TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is $\geq$ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Pressure-High and the Average Power Range Monitor Neutron Flux-High (Fixed) Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 2. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low signals are initiated by low digital-electrohydraulic control (DEHC) fluid pressure in the emergency trip header for the control valves. There are four pressure switches which sense off the common header, with one pressure switch assigned to each separate RPS logic channel. This Function must be enabled at THERMAL POWER $\geq$ 30% RTP as measured by turbine first stage pressure. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is $\geq$ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP, since the Reactor Vessel Pressure-High and the Average Power Range Monitor Neutron Flux-High (Fixed) Functions are adequate to maintain the necessary safety margins.

10. Reactor Mode Switch-Shutdown Position

The Reactor Mode Switch-Shutdown Position Function provides signals, via the manual scram logic channels, directly to the scram pilot solenoid power circuits. These manual scram logic channels are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a keylock four-position, four-bank switch. The reactor mode switch will scram the reactor if it is placed in the shutdown position. Scram signals from the reactor mode switch are input into each of the two RPS manual scram logic channels.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

Two channels of Reactor Mode Switch-Shutdown Position Function, with one channel in each manual scram trip system, are available and required to be OPERABLE. The Reactor Mode Switch-Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, directly to the scram pilot solenoid power circuits. These manual scram logic channels are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the two RPS manual scram logic channels. In order to cause a scram it is necessary that the channel in both manual scram trip systems be actuated.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Two channels of Manual Scram with one channel in each manual scram trip system are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

BASES

ACTIONS (continued)

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 10) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system. For Items 7.a and 7.b (Scram Discharge Volume Water Level - High, Level Transmitter and Level Switch), entry into Condition B is required when at least one channel (either an Item 7.a or 7.b channel) is inoperable in each trip system associated with one SDV.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 10 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 10, which justified a

BASES

ACTIONS (continued)

12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve-Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip). For Items 7.a and 7.b (Scram Discharge Volume Water Level - High, Level Transmitter and Level Switch), this would require both trip systems in each SDV to have one channel (either an Item 7.a or 7.b channel)

BASES

ACTIONS (continued)

OPERABLE or in trip (or the associated trip system in trip). For Function 8 (Turbine Stop Valve-Closure), this would require both trip systems to have two channels, each OPERABLE or in trip (or the associated trip system in trip). For Functions 10 (Reactor Mode Switch-Shutdown Position) and 11 (Manual Scram) this would require both trip systems to have one channel each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, and G.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

BASES

ACTIONS (continued)

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 10) assumption of the average time required to perform channel Surveillances. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.1

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At ≥ 25% RTP, the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 10).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.4

There are four RPS channel test switches, one associated with each of the four automatic scram logic channels (A1, A2, B1, and B2). These keylock switches allow the operator to test the OPERABILITY of each individual logic channel (i.e., test through the K14 relay) without the necessity of using a scram function trip. This is accomplished by placing the RPS channel test switch in test, which will input a trip signal into the associated RPS logic channel. The RPS channel test switches are not specifically credited in the accident analysis. However, because the Manual Scram Functions at CNS were not configured the same as the generic model in Reference 10, the RPS channel test switches were included in the analysis in Reference 11. Reference 11 concluded that the Surveillance Frequency extensions for RPS Functions, described in Reference 10, were not affected by the difference in configuration, since each automatic RPS channel has a test switch which is functionally the same as the manual scram switches in the generic model. As such, a functional test of each RPS channel test switch is required to be performed once every 7 days. The Frequency of 7 days is based on the reliability analysis of Reference 11.

SR 3.3.1.1.5 and SR 3.3.1.1.6

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a neutron flux region without adequate indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. On controlled shutdowns, the IRM reading 121/125 of full scale will be set equal to or less than 45% of rated power. All range scales above that scale on

BASES

SURVEILLANCE REQUIREMENTS (continued)

which the most recent IRM calibration was performed will be mechanically blocked. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, all operable IRM channels shall be on scale.

As noted, SR 3.3.1.1.6 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.7

This SR ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a valid core flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. If the flow unit signal is not within the appropriate flow limit, the affected APRMs that receive an input from the inoperable flow unit must be declared inoperable.

The Frequency of 31 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.11

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 10.

The 18 month Frequency of SR 3.3.1.1.11 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. Testing of Function 10 requires placing the mode switch in "Shutdown". Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.10 and SR 3.3.1.1.12

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. Physical inspection of the position switches is performed in conjunction with SR 3.3.1.1.12 for Functions 5, 7.b, and 8 to ensure that the switches are not corroded or otherwise degraded.

Note 1 of SR 3.3.1.1.10 and SR 3.3.1.1.12 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). Note 1 of SR 3.3.1.1.10 states that recirculation loop flow

BASES

SURVEILLANCE REQUIREMENTS (continued)

transmitters are excluded from CHANNEL CALIBRATION. This exclusion is based on calculation results and site-specific instrument setpoint drift data, which alternately supports an 18-month calibration interval for the recirculation loop flow transmitters. As such, the flow transmitters are calibrated on an 18-month frequency as required by SR 3.3.1.1.12 for Function 2b.

A second Note to SR 3.3.1.1.12 is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.10 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.12 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.13

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER ≥ 30% RTP to ensure that the calibration is valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, then the affected Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Open main turbine bypass valve(s) can also affect these two functions. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 12.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

BASES

REFERENCES

1. USAR, Section VII-2.

2. USAR, Chapter XIV.

3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

4. USAR, Section VI-5.

5. 10 CFR 50.36(c)(2)(ii).

6. USAR, Section IV-4.9.

7. USAR, Section XIV-6.2.

8. USAR, Section XIV-5.4.3.

9. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

10. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

11. MDE-94-0485, "Technical Specification Improvement Analysis for the Reactor Protection System for Cooper Nuclear Station," April 1985.

12. USAR, VII-2.3.9.10.

BASES

SURVEILLANCE REQUIREMENTS (continued)

is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or 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 instrument has drifted outside its limit.

The Frequency of once every 12 hours for SR 3.3.1.2.1 is based on operating experience that demonstrates channel failure is rare. While in MODES 3 and 4, reactivity changes are not expected; therefore, the 12 hour Frequency is relaxed to 24 hours for SR 3.3.1.2.3. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core when the fueled region encompasses more than one SRM, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that the SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE (when the fueled region encompasses only one SRM), per Table 3.3.1.2-1, footnote (b), only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The 12 hour Frequency is based upon operating experience and supplements operational controls over refueling activities that include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate with the detector full-in, which ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met on an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated core quadrant, even with a control rod withdrawn, the configuration will not be critical. This SR does not require determination of the noise ratio.

The Frequency is based upon channel redundancy and other information available in the control room, and ensures that the required channels are frequently monitored while core reactivity changes are occurring. When no reactivity changes are in progress, the Frequency is relaxed from 12 hours to 24 hours.

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. 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. SR 3.3.1.2.5 is required in MODE 5, and the 7 day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. This Frequency is reasonable, based on operating experience and on other Surveillances (such as a

BASES

SURVEILLANCE REQUIREMENTS (continued)

CHANNEL CHECK), that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

SR 3.3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below, and in MODES 3 and 4. Since core reactivity changes do not normally take place in MODES 3 and 4, and core reactivity changes are due only to control rod movement in MODE 2, the Frequency has been extended from 7 days to 31 days. The 31 day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

Verification of the signal to noise ratio also ensures that the detectors are inserted to an acceptable operating level. In a fully withdrawn condition, the detectors are sufficiently removed from the fueled region of the core to essentially eliminate neutrons from reaching the detector. Any count rate obtained while the detectors are fully withdrawn is assumed to be "noise" only.

The Note to SR 3.3.1.2.6 allows the Surveillance to be delayed until entry into the specified condition of the Applicability (THERMAL POWER decreased to IRM Range 2 or below). The SR must be performed within 12 hours after IRMs are on Range 2 or below. The allowance to enter the Applicability with the 31 day Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION at a Frequency of 18 months verifies the performance of the SRM detectors and associated circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) because they cannot readily be adjusted. The detectors are fission chambers that are

BASES

SURVEILLANCE REQUIREMENTS (continued)

designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life.

Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the 18 month Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES None.

BASES

SURVEILLANCE REQUIREMENTS (continued)

for up to 6 hours provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 8) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that a control rod block will be initiated when necessary.

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the channel will perform the intended function. It includes the Reactor Manual Control System input. It also includes the local alarm lights representing upscale and downscale trips, but no rod block will be produced at this time. 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 shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 92 days is based on reliability analyses (Ref. 9).

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the system will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 CHANNEL FUNCTIONAL TEST for the RWM includes performing the RWM computer on line diagnostic test satisfactorily, attempting to withdraw a control rod not in compliance with the prescribed

BASES

SURVEILLANCE REQUIREMENTS (continued)

sequence and verifying a control rod block occurs. For SR 3.3.2.1.2, the CHANNEL FUNCTIONAL TEST also includes attempting to select a control rod not in compliance with the prescribed sequence and verifying a selection error occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn in MODE 2. As noted, SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 10% RTP for SR 3.3.2.1.3, to perform the required Surveillance if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The Frequencies are based on reliability analysis (Ref. 9).

SR 3.3.2.1.4

The RBM power range setpoints control the enforcement of the appropriate upscale trips over the proper core thermal power range of the Applicability Notes (a), (b), (c), (d), and (e) of ITS Table 3.3.2.1-1. The RBM Upscale Trip Function setpoints are automatically varied as a function of power. Three Allowable Values are specified in the COLR as denoted in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values automatically change are based on the reference APRM signal's input to each RBM channel. Below the minimum power setpoint of 30% RTP or when a peripheral control rod is selected, the RBM is automatically bypassed. These power Allowable Values must be verified periodically by determining that the power level setpoints are less than or equal to the specified values. If any power range setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the power range channel can be placed in the conservative condition (i.e., enabling the proper RBM setpoint). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8. The 184 day Frequency is based on the actual trip setpoint methodology utilized for these channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

As noted, neutron detectors are excluded from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8.

The Frequency is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from feedwater flow and steam flow signals. The setpoint where the automatic bypass feature is unbypassed must be verified periodically to be > 10% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The Frequency is based on the trip setpoint methodology utilized for the low power setpoint channel.

SR 3.3.2.1.7

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch — Shutdown Position Function to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical

BASES

SURVEILLANCE REQUIREMENTS (continued)

Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch — Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the 18 month Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.2.1.8

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

BASES

REFERENCES

1. USAR, Section VII-7.

2. USAR, Section VII-16.3.3.

3. NEDC-31892P, "Extended Load Line Limit and ARTS Improvement Program Analyses for Cooper Nuclear Station," Rev. 1, May 1991.

4. 10 CFR 50.36(c)(2)(ii).

5. USAR, Section XIV-6.2.

6. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

7. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.

8. GENE-770-06-1, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

9. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 3.

SR 3.3.4.1.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. For the Reactor Vessel Water Level-Low Low (Level 2) logic, this shall include the nominal 9 second time delay of the RRMG field breaker trip. The system functional test of the RRMG field breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if

BASES

SURVEILLANCE REQUIREMENTS (continued)

an RRMG field breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. USAR, Section VII-9.4.4.2.

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

3. GENE-770-06-1, "Bases for Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APLICABILITY

1.d, 2.g. Core Spray and Low Pressure Coolant InjectionPump Discharge Flow-Low (Bypass)

flow rate is sufficient to protect the pump.

Each channel of Pump Discharge Flow — Low Function (two CS channels and four LPCI channels) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude the ECCS function. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.e. Core Spray Pump Start-Time Delay Relay

The purpose of this time delay is to delay the start of the CS pumps to enable sequential loading of the appropriate AC source. This Function is necessary when power is being supplied from the offsite sources or the standby power sources (DG). The CS Pump Start-Time Delay Relays are assumed to be OPERABLE in the accident analyses requiring ECCS initiation. That is, the analyses assume that the pumps will initiate when required and excess loading will not cause failure of the power sources.

There are two Core Spray Pump Start-Time Delay Relays, one for each CS pump. Each time delay relay is dedicated to a single pump start logic, such that a single failure of a Core Spray Pump Start-Time Delay Relay will not result in the failure of more than one CS pump. In this condition, one of the two CS pumps will remain OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Value for the Core Spray Pump Start-Time Delay Relays is chosen to be long enough so that the power source will not be overloaded and short enough so that ECCS operation is not degraded.

Each channel of Core Spray Pump Start-Time Delay Relay Function is required to be OPERABLE only when the associated CD subsystem is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the CS subsystems.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLITY

3.f. High Pressure Coolant Injection Pump Discharge Flow-Low (Bypass)

OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

The minimum flow instrument is provided to protect the HPCI pump from overheating when the pump is operating at reduced flow. The minimum flow line valve is opened when low flow is sensed and either 1) the pump is on, or 2) the system has initiated; and the valve is automatically closed when the flow rate is adequate to protect the pump. The High Pressure Coolant Injection Pump Discharge Flow — Low Function is assumed to be OPERABLE. The minimum flow valve for HPCI is not required to close to ensure that the ECCS flow assumed during the transients analyzed in References 5, 6, and 7 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch is used to detect the HPCI System's flow rate. The logic is arranged such that the switch causes the minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded.

The High Pressure Coolant Injection Pump Discharge Flow — Low Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump.

One channel is required to be OPERABLE when the HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level-Low Low Low (Level 1)

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this

BASES

SURVEILLANCE REQUIREMENTS (continued)

approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited to 12 hours; 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 instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of Reference 8.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.3 and SR 3.3.5.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.5.1.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

The Frequency of SR 3.3.5.1.4 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic and simulated automatic actuation for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. Amendment No. 7 to Facility License No DPR-46 for the Cooper Nuclear Station, February 6, 1975.

2. Cooper Nuclear Station Design Change 94-332, December 1994.

3. NEDC 97-023, "HPCI Minimum Flow Line Analysis."

4. 10 CFR 50.36(c)(2)(ii).

5. USAR, Section V-2.4.

6. USAR, Section VI-5.0.

7. USAR, Chapter XIV.

8. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 2.

SR 3.3.5.2.3 and SR 3.3.5.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of SR 3.3.5.2.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

The Frequency of SR 3.3.5.2.4 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function. Simulated automatic actuation is performed each operating cycle.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).

2. GENE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 10 and 11) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analysis described in References 10 and 11.

SR 3.3.6.1.3, SR 3.3.6.1.4 and SR 3.3.6.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. SR 3.3.6.1.5, however, is only a calibration of the radiation detectors using a standard radiation source.

As noted for SR 3.3.6.1.4, the main steam line radiation detectors (Function 2.d) are excluded from CHANNEL CALIBRATION due to ALARA reasons (when the plant is operating, the radiation detectors are generally in a high radiation area; the steam tunnel). This exclusion is acceptable because the radiation detectors are passive devices, with minimal drift. The radiation detectors are calibrated in accordance with SR 3.3.6.1.5 on an 18 month Frequency using a standard current source and radiation source. The CHANNEL CALIBRATION of the remaining portions of the channel (SR 3.3.6.1.4) are performed using a standard current source.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of SR 3.3.6.1.3 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.6.1.4 and SR 3.3.6.1.5 is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. Simulated automatic actuation is performed each operating cycle. The 18 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. USAR, Table V-2-2.

2. USAR, Chapter XIV.

3. 10 CFR 50.36(c)(2)(ii).

4. USAR, Section XIV-6.3.

5. USAR, Section XIV-5.4.1.

6. USAR, Section XIV-6.5.

7. USAR, Section XIV-6.7.1.

8. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.

9. USAR, Section IV-9.3.

10. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

11. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.1

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 5 and 6.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.6.2.3 is based on the assumption of an 18 month calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. USAR, Section V-3.0.

2. USAR, Chapter XIV.

3. 10 CFR 50.36(c)(2)(ii).

4. USAR, Sections XIV-6.3 and XIV-6.4.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.

6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

BASES

ACTIONS (continued)

B.1

If the Required Action and associated Completion Time of Condition A is not met, or both LLS valves are inoperable due to inoperable channels, the LLS valves may be incapable of performing their intended function. Therefore, the associated LLS valve must be declared inoperable immediately. A LLS valve is OPERABLE if the associated logic (e.g., Logic A) has one Function 1 channel, two Function 2 channels, and four Function 3 channels OPERABLE.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LLS instrumentation Function are located in the SRs column of Table 3.3.6.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability. LLS initiation capability is maintained provided one LLS valve can be initiated by the LLS instrumentation. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the LLS valves will initiate when necessary.

SR 3.3.6.3.1, SR 3.3.6.3.2, and SR 3.3.6.3.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 92 day Frequency is based on the reliability analysis of Reference 3.

A portion of the SRV discharge line pressure switch instrument channels are located inside the primary containment. The Note for SR 3.3.6.3.2, "Only required to be performed prior to entering MODE 2 during each scheduled outage > 72 hours when entry is made into primary containment," is based on the location of these instruments and ALARA considerations.

SR 3.3.6.3.4

CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of once every 18 months for SR 3.3.6.3.4 is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.3.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specified channel. The system functional testing performed in LCO 3.4.3, "Safety/Relief Valves (SRVs) and Safety Valves (SVs)" and LCO 3.6.1.6, "Low-Low Set (LLS) Safety/Relief Valves (SRVs)," for SRVs overlaps this test to provide complete testing of the assumed safety function.

The Frequency of once every 18 months for SR 3.3.6.3.5 is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. USAR, Section IV-4.5.2.

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

3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Filter (CREF) System Instrumentation

BASES

BACKGROUND

The CREF System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. The instrumentation and controls for the CREF System automatically isolate the normal ventilation intake and initiate action to pressurize the main control room and filter incoming air to minimize the infiltration of radioactive material into the control room environment.

In the event of a loss of coolant accident (LOCA) signal (Reactor Vessel Water Level — Low, Level 3 or Drywell Pressure — High) or Reactor Building Ventilation Exhaust Plenum Radiation — High signal, the normal control room inlet supply damper closes and the CREF System is automatically started in the emergency bypass mode. The air drawn in from the outside passes through a high efficiency filter and a charcoal filter in sufficient volume to maintain the control room slightly pressurized with respect to the adjacent areas.

The CREF System instrumentation has two trip systems. Each trip system includes the sensors, relays, and switches necessary to cause initiation of the CREF System. Each trip system receives input from each of the Functions listed above (each sensor sends a signal to both trip systems). The Reactor Vessel Water Level — Low, Level 3, Drywell Pressure — High, and Reactor Building Ventilation Exhaust Plenum Radiation — High are each arranged in a one-out-of-two taken twice logic for each trip system. The channels include electronic and electrical equipment (e.g., switches and trip relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a CREF System initiation signal to the initiation logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CREF System to maintain the habitability of the control room is explicitly assumed for certain accidents as discussed in the USAR safety analyses (Refs. 1, 2, and 3). CREF System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents that assume CREF System operation, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

CREF System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

The OPERABILITY of the CREF System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. Each Function must have the required number of OPERABLE channels, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each CREF System Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The setpoint calculations are performed using methodology described in NEDC-31336P-A, "General Electric Instrument Setpoint Methodology," dated September 1996. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limit, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level — Low (Level 3)

Low reactor pressure vessel (RPV) water level indicates that the capability of cooling the fuel may be threatened. A low reactor vessel water level could indicate a LOCA and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Reactor Vessel Water Level — Low (Level 3) signals are initiated from level switches that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Eight channels of Reactor Vessel Water Level — Low (Level 3) Function are available and are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude CREF System initiation.

The Reactor Vessel Water Level — Low (Level 3) Allowable Value was chosen to be the same as the RPS Level scram Allowable Value (LCO 3.3.1.1) to enable initiation of the CREF System at the earliest indication of a breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious initiation.

The Reactor Vessel Water Level — Low (Level 3) Function is required to be OPERABLE in MODES 1, 2, and 3, and during operations with a potential for draining the reactor vessel (OPDRVs) to ensure that the Control Room personnel are protected during a LOCA. In MODES 4 and 5 at times other than OPDRVs, the probability of a vessel draindown event resulting in the release of radioactive material to the environment is minimal. Therefore, this Function is not required in other MODES and specified conditions.

2. Drywell Pressure — High

High drywell pressure can indicate a break in the reactor coolant pressure boundary. A high drywell pressure signal could indicate a LOCA and will automatically initiate the CREF System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure — High (continued)

Drywell Pressure — High signals are initiated from pressure switches that sense drywell pressure. Eight channels of Drywell Pressure — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude performance of the isolation function. The Drywell Pressure — High Allowable Value was chosen to be the same as the ECCS Drywell Pressure — High Function Allowable Value (LCO 3.3.5.1).

The Drywell Pressure — High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected in the event of a LOCA. In MODES 4 and 5, the Drywell Pressure— High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure — High setpoint.

3. Reactor Building Ventilation Exhaust Plenum Radiation— High

High radiation in the refueling floor area could be the result of a fuel handling accident. A refueling floor high radiation signal will automatically initiate the CREF System, since this radiation release could result in radiation exposure to control room personnel.

The Reactor Building Exhaust Plenum Radiation — High signals are initiated from radiation detectors that are located such that they can monitor the radioactivity of gas flowing through the reactor building exhaust plenum. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel in each trip system. Four channels of Reactor Building Ventilation Exhaust Plenum Radiation — High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the CREF System initiation. The Allowable Value was chosen to promptly detect gross failure of the fuel cladding.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Building Ventilation Exhaust Plenum Radiation— High (continued)

The Reactor Building Ventilation Exhaust Plenum Radiation— High Function is required to be OPERABLE in MODES 1, 2, and 3 and during movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and operations with a potential for draining the reactor vessel (OPDRVs), to ensure control room personnel are protected during a pipe break resulting in significant releases of radioactive steam and gas, fuel handling event, or vessel draindown event. During MODES 4 and 5, when these specified conditions are not in progress (e.g., CORE ALTERATIONS), the probability of a pipe break resulting in significant releases of radioactive steam and gas or fuel damage is low; thus, the Function is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to CREF System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable CREF System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable CREF System instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the common interface with the Secondary Containment isolation Instrumentation, allowable out of service time of 12 hours for Functions 1 and 2, and 24 hours for Function 3, has been shown to be acceptable (Refs. 5, 6, and 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining CREF System initiation capability. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be

BASES

ACTIONS

A.1 (continued)

placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure in the trip system, and allow operation to continue. Alternately, if it is not desired to place the channel in trip, Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that at least one trip system will generate a trip signal from the given Function on a valid signal.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

If the CREF System initiation capability cannot be restored within the Completion Time, Condition C must be entered and its Required Actions taken.

C.1

With any Required Action and associated Completion Time of Condition A or B not met, the CREF System must be placed in operation per Required Action C.1 to ensure that control room personnel will be protected in the event of a Design Basis Accident which assumes a CREF System initiation. The method used to place the CREF System in operation must provide for automatically re-initiating the system upon restoration of power following a loss of power to the CREF System. Alternatively, if it is not desired to start the CREF System, the CREF System must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREF System in operation. The 1 hour completion time is

BASES

ACTIONS

C.1 (continued)

acceptable because it minimizes risk while allowing time for restoration or tripping of channels, for placing the CREF System in operation, or for entering the applicable Conditions and Required Actions for the inoperable CREF System.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each CREF System instrumentation Function are located in the SRs column of Table 3.3.7.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains CREF System initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 5, 6, and 7) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the CREF System will initiate when necessary.

SR 3.3.7.1.1

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (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 instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 5, 6, and 7.

SR 3.3.7.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.3 (continued)

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

SR 3.3.7.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.4, "Control Room Emergency Filter (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. USAR, Section X-10.4.
2. USAR, Section XIV-6.3.
3. USAR, Section XIV-6.4.
4. 10 CFR 50.36(c)(2)(ii).
5. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.
6. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
7. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses and the power to the buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different types of undervoltage protection: Loss of Voltage and Degraded Voltage (Ref. 1). There are three Loss of Voltage relays associated with each 4.16 kV Emergency Bus or power supply to that bus constituting three separate Functions: 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) - Function 1, 4.16 kV Emergency Bus Normal Supply Undervoltage (Loss of Voltage) - Function 2, and 4.16 kV Emergency Bus ESST (Emergency Station Service Transformer) Supply Undervoltage (Loss of Voltage) - Function 3. These three Functions constitute the first level of undervoltage protection. Voltage on 4.16 kV Emergency Bus 1F (1G) is monitored by relay 27/1F1 (27/1G1) - Function 1; voltage on the normal supply bus tie to 4.16 kV Emergency Bus 1F (1G) is monitored by relay 27/1FA1 (27/1GB1) - Function 2; and voltage on the ESST supply bus tie to 4.16 kV Emergency Bus 1F (1G) is monitored by relay 27/ET1 (27/ET2) - Function 3. Upon sensing a loss of voltage to Emergency Bus 1F (1G), the Function 1 relay 27/1F1 (27/1G1) will initiate the following:

1. A start signal to DG1 (DG2).

2. Load shedding of all motors on 4.16 kV Emergency Bus 1F (1G).

3. Load shedding of the non-essential Motor Control Centers (MCC) and non-essential motors fed from Emergency 480 V Bus 1F (1G).

BASES

BACKGROUND

The Function 2 undervoltage relay 27/1FA1 (27/1GB1) will then trip breaker 1FA (1GB) if the Emergency Bus 1F (1G) is being supplied from its normal source (either the normal station service transformer (NSST) or the startup station service transformer (SSST)); or the Function 3 undervoltage relay 27/ET1 (27/ET2) will trip breaker 1FS (1GS) if the 4.16 kV Emergency Bus 1F (1G) is being supplied from its alternate source, the ESST. Opening breakers 1FA (1GB) and 1FS (1GS) will then allow the diesel generator, DG1 (DG2) to connect to 4.16 kV Emergency Bus 1F (1G).

The second level of undervoltage protection is a Degraded Voltage scheme. Voltage on 4.16 kV Emergency Bus 1F (1G) is monitored by relay 27/1F2 (27/1G2) and voltage on the normal supply bus tie to emergency bus 1F (1G) is monitored by relay 27/1FA2 (27/1GB2). When 4.16 kV Emergency Bus 1F (1G) is energized from its normal source, a degraded voltage condition will be sensed by two relays 27/1F2 (27/1G2) and 27/1FA2 (27/1GB2) - Function 4. When 4.16 kV Emergency Bus 1F (1G) is energized from the ESST, a degraded voltage condition on 4.16 kV Emergency Bus 1F (1G) will be sensed by only one relay, 27/1F2 (27/1G2) - Function 5. When 4.16 kV Emergency Bus 1F (1G) is powered from the normal supply, a degraded voltage condition on 4.16 kV Emergency Bus 1F (1G) for approximately 12.5 seconds (Function 4.c) will trip the tie breaker 1FA (1GB) unless an RHR initiation seal-in is present, in which case breaker 1FA (1GB) will trip on a degraded voltage on bus 1F (1G) after approximately 7.5 seconds (Function 4.b). When 4.16 kV Emergency Bus 1F (1G) is powered from the ESST, a degraded voltage condition on 4.16 kV Emergency Bus 1F (1G) for approximately 15 seconds (Function 5.b) will trip breaker 1FS (1GS). The three Loss of Voltage relays are each arranged in a one-out-of-one logic configuration (Functions 1, 2, and 3), while the Degraded Voltage relays are arranged in a two-out-of-two logic configuration if the emergency bus is powered from its normal source (Function 4), or in a one-out-of-one logic configuration if the emergency bus is powered from the ESST (Function 5). The channels include electronic equipment (e.g., internal relay contacts, coils, solid state logic, etc.) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 2 analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

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

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., internal relay contact) changes state. The Allowable Values are derived from the limiting values of the process parameters obtained from the safety analysis. For all LOP Instrumentation Functions, the Allowable Values and the trip setpoints are determined from historically accepted practice relative to the intended functions of the channels.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1.a, 1.b 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

Upon loss of voltage, relay 27/1F1 (27/1G1) will initiate a start signal to DG1 (DG2), load shedding of all motors on 4.16 kV Emergency Bus 1F (1G), and load shedding of the non-essential Motor Control Centers (MCCs) and non-essential motors fed from critical 480 V Bus 1F (1G)

The 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Allowable Value is low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

One channel of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and Time Delay Function per associated 4.16 kV emergency bus is available and is only required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1, "AC Sources — Operating," and 3.8.2, "AC Sources — Shutdown," for Applicability Bases for the DGs.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a, 2.b 4.16 kV Emergency Bus Normal Supply Undervoltage (Loss of Voltage)

Loss of voltage on the SWGR 1A to 1F (1B to 1G) bus tie indicates that offsite power is not available from the normal source (NSST or SSST). Therefore, in order to allow the emergency bus to be powered from the alternate offsite power source (ESST) or the DG, relay 27/1FA-1 (27/1GB-1) will cause the normal supply breaker to the 4.16 kV emergency bus, 1FA (1GB) to trip following the actuation of the Function 1 channels following a short time delay.

The 4.16 kV Emergency Bus Normal Supply Undervoltage (Loss of Voltage) Allowable Value is low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are chosen to assure timely operation for a loss of voltage condition, but not allow spurious operation during momentary voltage dips created by motor starts.

One channel of 4.16 kV Emergency Bus Normal Supply Undervoltage (Loss of Voltage) Function and Time Delay Function per associated 4.16 kV emergency bus is available and is only required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1, "AC Sources-Operating," and 3.8.2, "AC Sources-Shutdown," for Applicability Bases for the DGs.

3.a, 3.b 4.16 kV Emergency Bus ESST Supply Undervoltage (Loss of Voltage)

Loss of voltage on the ESST-1F (1G) bus tie indicates that offsite power is not available from the alternate offsite source (ESST). Therefore, in order to allow the 4.16 kV emergency bus to be powered from the DG following loss of the alternate offsite source, relay 27/ET-1 (27/ET-2) will cause the ESST-1F (1G) breaker 1FS (1GS) to trip following a short time delay, which in turn will allow the DG output breaker to close.

The 4.16 kV Emergency Bus ESST Supply Undervoltage (Loss of Voltage) Allowable Value is low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are long enough

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a, 3.b 4.16 kV Emergency Bus ESST Supply Undervoltage (Loss of Voltage) (continued)

to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

One channel of 4.16 kV Emergency Bus ESST Supply Undervoltage (Loss of Voltage) Function and Time Delay Function per associated 4.16 kV emergency bus is available and is only required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1, "AC Sources-Operating," and 3.8.2, "AC Sources-Shutdown," for Applicability Bases for the DGs.

4.a, 4.b, 4.c 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from normal offsite power to alternate offsite power or to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Value (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

A degraded voltage condition on 4.16 kV Emergency Bus 1F (1G) is monitored by relays 27/1F2 (27/1G2) and 27/1FA2 (27/1GB2). Any momentary voltage dips caused by starting of large motors will not operate undervoltage relays. When 4.16 kV Emergency Bus 1F (1G) is powered from either the SSST or NSST, a degraded voltage on 4.16 kV Emergency Bus 1F (1G) below a nominal value of 3,880 V for approximately 12.5 seconds sensed by both relays 27/1F2 (27/1G2) and 27/1FA2 (27/1GB2) will trip the tie breaker 1FA (1GB) unless a LOCA seal-in signal is present, in which case time delay relay 27X7/1F (27X7/1G) will be bypassed and breaker 1FA (1GB) will trip if voltage on 4.16 kV Emergency Bus 1F (1G) is below a nominal value of 3,880 V for 7.5 seconds.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a, 4.b, 4.c 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

The Bus Undervoltage Allowable Value is low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Value is long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function and Time Delay Function per associated bus are available and are required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

5.a, 5.b 4.16 kV Emergency Bus ESST Supply Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from the alternate offsite power source to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Value (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

When 4.16 kV Emergency Bus 1F (1G) is energized from the ESST, degraded voltages will be sensed by only one relay 27/1F2 (27/1G2). Any momentary voltage dips caused by starting of large motors will not operate undervoltage relays. When 4.16 kV Emergency Bus 1F (1G) is powered from the ESST, a degraded voltage on 4.16 kV Emergency Bus 1F (1G) for approximately 15 seconds will trip breaker 1FS (1GS). The nominal 15 second time delay consists of the nominal 7.5 second time delay from relay 27/1F2 (27/1G2) plus a nominal 7.5 second time delay from time delay relay 27X15/1F (27X15/1G). After the ESST breaker 1FS (1GS) trips, the Loss of Voltage protection system will start the associated DG and will trip all 4,000 volt motor breakers and non-essential MCC

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a, 5.b 4.16 kV Emergency Bus ESST Supply Undervoltage (Degraded Voltage) (continued)

breakers. The 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Allowable Value is low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Value is long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

One channel of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function and Time Delay Function per associated bus is available and is only required to be OPERABLE when the associated DG is required to be OPERABLE. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more channels of a Function inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the channel is not restored to OPERABLE status in 1 hour, Condition B must be entered and its Required Action taken.

BASES

ACTIONS

A.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs (Note 1), the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are further modified by a Note (Note 2) to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains initiation capability. Initiation capability is maintained provided that the following can be initiated by the Function for one DG or emergency bus as applicable (if part of that Function): DG start, disconnect from offsite power source, DG output breaker closure, and load shed. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable 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 shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

SR 3.3.8.1.2

A CHANNEL CALIBRATION is a complete check of the relay circuitry and associated time delay relays. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.8.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1.3 (continued)

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. USAR, Section VIII-3.6.
2. USAR, Chapter XIV.
3. 10 CFR 50.36(c)(2)(ii)

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic and scram solenoids.

RPS electric power monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both inseries electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram solenoids may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the MG set or the alternate power supply exceeds predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

BASES

APPLICABLE SAFETY ANALYSES

The RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS components that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent on the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS components. Each of the inservice electric power monitoring assembly trip logic setpoints is required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.1). Nominal trip setpoints are specified in the setpoint calculations. The setpoint calculations are performed using methodology described in NEDC-31336P-A, "General Electric Instrument Setpoint Methodology," dated September 1996. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift).

BASES

LCO

The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 10 V (to scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS components from the MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable assembly to OPERABLE status. If the inoperable assembly cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

BASES

A.1 (continued)

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly and the low probability of an event requiring RPS electric power monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternately, if it is not desired to remove the power supply from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable or both power monitoring assemblies in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1 or 2, a plant shutdown must be performed.

BASES

ACTIONS

C.1 (continued)

This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power condition in an orderly manner and without challenging plant systems.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action D.1 results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. Action must continue until the Required Action is completed.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.2

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly. The system functional test shall include actuation of the protective relays, tripping logic, and output circuit breakers. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. USAR, Section VII-2.3.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. 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 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string. The Frequency is 92 days and operating experience has proven this Frequency is acceptable.

REFERENCES

1. USAR, Section IV-10.2.
2. Regulatory Guide 1.45, May 1973.
3. USAR, Section IV-10.3.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austetic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. USAR, Section IV-10.3.2.
7. 10 CFR 50.36(c)(2)(ii).

ACTIONS (continued)

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures that appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these actions would not be required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to MSIV leakage not within limit, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. A remote manual valve may be considered a manual valve once deactivated. With remote operation capability maintained, the remote manual valve is not considered a manual valve. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in

ACTIONS (continued)

the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by 2 Notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable, except due to MSIV leakage not within a limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely

ACTIONS (continued)

affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A remote manual valve may be considered a manual valve once deactivated. With remote operation capability maintained, the remote manual valve is not considered a manual valve. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. A remote manual valve may be considered a manual valve once deactivated. With remote operation capability maintained, the remote manual valve is not considered a manual valve. Required Action C.1 must be completed within 4 hours for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines. The Completion Time of 4 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected

ACTIONS (continued)

penetration is isolated is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by 2 Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

With any MSIV leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. A remote manual valve may be considered a manual valve once deactivated. With remote operation capability maintained, the remote manual valve is not considered a manual valve. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 8 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration, the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown, and the relative importance of MSIV leakage to the overall containment function.

ACTIONS (continued)

E.1 and E.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required to be OPERABLE during MODE 4 or 5, the unit must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended and valve(s) are restored to OPERABLE status. If suspending an OPDRV would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the 24 inch primary containment purge and vent valves are closed as required or, if open, open for an allowable reason. If a purge or vent valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by Note 1 stating that the SR is not required to be met when the purge and vent valves are open for the stated reasons. Note 1 states that these valves may be opened in one supply line and one exhaust line for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Note 2 modifies the SR by requiring both Standby Gas Treatment (SGT) subsystems OPERABLE and only one SGT subsystem operating when these purge and vent valves are open in accordance with Note 1.

SR 3.6.1.3.6 (continued)

calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 18 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8

This SR requires a demonstration that a representative sample of reactor instrumentation line excess flow check valves (EFCVs) are OPERABLE by verifying that each valve actuates to the isolation position on an actual or simulated instrument line break. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested at least once every 10 years (nominal). This SR provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during the postulated instrument line break event. The 18 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

The nominal 10 year interval is based on other performance-based testing programs, such as Inservice Testing (snubbers) and Option B to 10 CFR 50, Appendix J. Furthermore, any EFCV failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND

The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell fan coil units remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 4 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment and equipment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Refs. 1 and 4). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 2). Analyses assume an initial average drywell air temperature of 150°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable structural temperature of 281°F. Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident.

Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii) (Ref. 3).

LCO

In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant drywell structural temperature is maintained below the maximum allowable. As a result, the ability of primary containment to perform its design function is ensured.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24 hour Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.

REFERENCES

1. USAR, Section XIV-6.3.
2. USAR, Table V-2-1.
3. 10 CFR 50.36(c)(2)(ii).
4. USAR, Section VI-5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA) to limit fission product release to the environment. In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products released to the environment and to limit fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSES

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that fission products entrapped within the secondary containment structure following secondary containment isolation will be treated by the SGT System prior to discharge to the environment.

BASES

APPLICABLE SAFETY ANALYSES

Secondary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

An OPERABLE secondary containment provides a control volume into which fission products that leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, following secondary containment isolation, can be processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 3) and a fuel handling accident (Ref. 4). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment System (SGT) System following secondary containment isolation, before being released to the environment.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment following secondary containment isolation so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO are listed in Reference 6.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 6.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to minimize leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section V-3.0.
2. USAR, Section XIV-6.0.
3. USAR, Section XIV-6.3.
4. USAR, Section XIV-6.4
5. 10 CFR 50.36(c)(2)(ii).
6. Technical Requirements Manual.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by USAR, Appendix F (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) and secondary containment isolation are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls. Both SGT subsystems share a common inlet plenum. This inlet plenum is connected to the reactor building exhaust plenum, the primary containment, and the HPCI turbine gland seal exhauster. Both SGT subsystems exhaust to the elevated release point (ERP) tower through a common exhaust duct served by two 100% capacity system fans. Both fans automatically start on a secondary containment isolation signal.

The SGT subsystem fan suctions are cross connected by a single duct and a throttled and locked manual cross tie valve to accommodate decay heat removal. SGT room air enters the train suction through a check valve and air operated damper, is drawn through the filter removing decay heat, passes through the cross tie ductwork to the opposite SGT subsystem fan, and is exhausted to the ERP tower.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A demister or moisture separator;

b. A rough prefilter;

c. An electric heater;

d. A high efficiency particulate air (HEPA) filter;

e. A charcoal adsorber;

f. A second HEPA filter; and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1 (continued)

fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR verifies that each SGT subsystem starts on receipt of an actual or simulated initiation signal. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components will pass the Surveillance when performed at the 18 month Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR verifies that the SGT units cross tie damper is in the correct position, and that each SGT room air supply check valve and each air operated SGT dilution air shutoff valve open when the associated SGT subsystem fan is running. This ensures that the ventilation mode of SGT System operation is available. If the position of the SGT units cross tie damper is greater than or less than the position required for two OPERABLE SGT subsystems and one SGT subsystem is isolated with initiation of that SGT subsystem prevented, then the SGT units cross tie

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.4 (continued)

damper position requirement of SR 3.6.4.3.4 continues to be met for the remaining OPERABLE SGT subsystem, since, in this condition, adequate ventilation is available for decay heat removal from the remaining OPERABLE SGT subsystem. However, both SGT subsystems are inoperable if the SGT units cross tie damper position requirement is not met and one SGT subsystem is not isolated with initiation of that SGT subsystem prevented. If either SGT room air supply check valve or either SGT dilution air shutoff valve is inoperable, then the associated SGT subsystem is inoperable. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components will pass the Surveillance when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Appendix F.
2. USAR, Section V-3.3.4.
3. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Emergency Filter System

BASES

BACKGROUND

The CREF System provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA).

The safety related function of the CREF System includes a single high efficiency air filtration system for emergency treatment of recirculated air or outside supply air. The system consists of a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a supply fan, an emergency booster fan, an exhaust booster fan, and the associated ductwork and dampers. Prefilters and HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The CREF System is a standby system. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room personnel), the CREF System automatically switches to the emergency bypass mode of operation to minimize infiltration of contaminated air into the control room. A system of dampers isolates the control room, and the recirculated air is routed through the filter system. Outside air is taken in at the normal ventilation intake and is mixed with the recirculated air after being passed through the charcoal adsorber filter for removal of airborne radioactive particles.

The CREF System is designed to maintain the control room environment for a 200 man day continuous occupancy after a DBA without exceeding 5 rem whole body dose or its equivalent to any part of the body. The CREF System will pressurize the control room to $\geq$ 0.1 inches water gauge to prevent infiltration of air from surrounding buildings and the outside atmosphere. CREF System operation in maintaining control room habitability is discussed in the USAR, Chapters X and XIV, (Refs. 1 and 2, respectively).

BASES

APPLICABLE SAFETY ANALYSES

The ability of the CREF System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in the USAR, Chapters X and XIV (Refs. 1 and 2, respectively). The CREF System is assumed to operate following a loss of coolant accident and a fuel handling accident.

The CREF System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

The CREF System is required to be OPERABLE, since total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The CREF System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE. The system is considered OPERABLE when its associated:

a. Fans are OPERABLE (one supply fan, the emergency booster fan and the exhaust booster fan);

b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors, such that the pressurization limit of SR 3.7.4.4 can be met. However, it is acceptable for access doors to be open for normal control room entry and exit, and not consider it to be a failure to meet the LCO.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.2

This SR verifies that the required CREF testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.4.3

This SR verifies that on an actual or simulated initiation signal, the CREF System starts and operates. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Control Room Emergency Filter (CREF) System Instrumentation," overlaps this SR to provide complete testing of the safety function. The 18 month Frequency is specified in Reference 4.

SR 3.7.4.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the CREF System. During the emergency mode of operation, the CREF System is designed to slightly pressurize the control room $\geq$ 0.1 inches water gauge positive pressure with respect to the adjacent areas to prevent unfiltered inleakage. The CREF System is designed to maintain this positive pressure at a flow rate of $\leq$ 990 cfm to the control room in the pressurization mode. The Frequency of 18 months is consistent with industry practice and other filtration systems SRs.

REFERENCES

1. USAR, Chapter X.
2. USAR, Chapter XIV.
3. 10 CFR 50.36(c)(2)(ii).
4. Regulatory Guide 1.52, Revision 2, March 1978.

BACKGROUND (continued)

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices (4.16 kV breakers), cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E critical buses. Specifically, the two qualified offsite circuits are defined as:

a. The SSST, with incoming disconnect 1611-D closed, energizing the transformer from the offsite network (with all lines upstream of the disconnect considered part of the offsite network and not part of the Technical Specification required offsite circuit). The offsite circuit also includes the circuit path to:

   i. 4.16 kV SWGR Bus 1F via breakers 1AS, 4.16 kV SWGR Bus 1A, and breakers 1AF and 1FA; and
   ii. 4.16 kV SWGR Bus 1G via breakers 1BS, 4.16 kV SWGR Bus 1B, and breakers 1BG and 1GB.

b. The ESST, with incoming disconnect ET-D1 closed, energizing the transformer from the offsite network (with all lines upstream of the disconnect considered part of the offsite network and not part of the Technical Specification required offsite circuit). The offsite circuit also includes the circuit path to:

   i. 4.16 kV SWGR Bus 1F via breaker 1FS; and
   ii. 4.16 kV SWGR Bus 1G via breakers 1GS.

During plant operation, the critical buses 1F and 1G are energized from the NSST when the main generator is online via bus 1A or 1B. If the normal transformer fails or the main generator trips off the line, an automatic fast transfer of the loads to the SSST occurs. The SSST rating is sufficient such that the emergency service loads can be connected under accident conditions while the buses are supplying normal plant loads.

In the event both the normal and startup power source are lost, the ESST will supply the critical buses 1F and 1G after a one second time delay to

BACKGROUND (continued)

provide load shedding. The ESST rating is sufficient such that, following load shedding, the emergency service loads can be sequentially connected under accident conditions.

The onsite standby power source for 4.16 kV critical buses 1F and 1G consists of two DGs. DG-1 and DG-2 are dedicated to critical buses 1F and 1G, respectively. A DG starts automatically on a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on a critical bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of critical bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the critical bus on a LOCA signal alone. Following the trip of offsite power, all loads are shed from the critical bus. When the DG is tied to the critical bus, loads are then sequentially connected to its respective critical bus. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG.

In the event of a loss of both offsite power sources, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the DGs in the process. Within 44 seconds after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service. The failure of any one DG does not impair safe shutdown because each DG serves an independent, redundant 4.16 kV critical bus. The remaining DG and critical bus have sufficient capacity to mitigate the consequences of a DBA, support the shutdown of the unit, and maintain the unit in a safe condition.

BACKGROUND (continued)

Ratings for the DGs satisfy the requirements of Safety Guide 9 (Ref. 3). DG-1 and DG-2 have the following ratings:

a. 4000 kW — continuous,

b. 4400 kW —2 hours per day,

c. 5000 kW — 320 hours/total.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the USAR, Chapter VI (Ref. 4) and Chapter XIV (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and two separate and independent DGs (DG-1 and DG-2) ensure availability of the required power to shut

LCO (continued)

down the reactor and maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA.

Qualified offsite circuits are those that are described in the USAR, and are part of the licensing basis for the unit.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the critical buses. Each offsite circuit consists of incoming disconnect to respective SSST or ESST, respective SSST and ESST transformers, and the respective circuit path including feeder breakers to the two 4.16 kV critical buses. For the SSST, the circuit also includes the intermediate non-critical bus.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective 4.16 kV critical bus on detection of bus undervoltage. This sequence must be accomplished within 14 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in standby with the engine at ambient condition. Proper sequencing of loads, including load shedding, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one 4.16 kV critical bus, with fast transfer capability, as applicable, to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to a critical bus is required to have OPERABLE automatic or fast transfer interlock mechanisms, as applicable, to both critical buses to support OPERABILITY of that circuit. That is, power can be supplied to both critical buses via the SSST provided that the automatic transfer capability to the ESST exists for both of the critical buses. However, if power is supplied to both critical buses via the ESST, then one offsite circuit is inoperable, since no automatic transfer capability from the ESST to the SSST exists.

BASES

LCO (continued)

Additionally, power to the critical buses is allowed to be supplied from the NSST. In this case, the SSST offsite circuit is considered OPERABLE provided the automatic transfer capability from the NSST to the SSST is OPERABLE for both of the critical buses. For the ESST to be considered OPERABLE, the automatic transfer capability from the NSST to the ESST must be OPERABLE for both critical buses (the automatic transfer capability from the NSST to the ESST is allowed to go through an intermediate step of transferring to the first offsite source, i.e., SSST).

A verification of OPERABILITY is an administrative check, by examination of appropriate plant records (logs, surveillance test records), to determine that a system, subsystem, train, component or device is not inoperable. Such verification does not preclude the demonstration (testing) of a given system, subsystem, train, component or device to determine OPERABILITY.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of abnormal operational transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the availability of the remaining offsite circuit

ACTIONS (continued)

on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if the second circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has no offsite power.

The Completion Time for Required Action A.2 is intended to allow time for the operator to evaluate and repair any discovered inoperabilities. This Completion Time also allows an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. The division has no offsite power supplying its loads; and

b. A redundant required feature on the other division is inoperable.

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

Discovering no offsite power to one 4.16 kV critical bus of the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with any other Class 1E bus that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required

ACTIONS A.2 (continued)

feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

The 4.16 kV critical bus design and loading is sufficient to allow operation to continue in Condition A for a period that should not exceed 7 days. 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.

The 7 day Completion Time takes into account the redundancy, capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 14 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 21 days) allowed prior to complete restoration of the LCO. The 14 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 7 day and 14 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Similar to Required Action A.2, the second Completion Time of Required Action A.3 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with one DG inoperable, 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 must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed to be powered from redundant safety related 4.16 kV critical buses. Redundant required features failures consist of inoperable features associated with a critical bus redundant to the critical bus that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A redundant required feature on the other division 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 DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the station to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single

ACTIONS B.2 (continued)

failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component 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, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), they are declared inoperable upon discovery, and Condition E of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of the remaining DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

BASES

ACTIONS

A.1 (continued)

immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. 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 CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.

REFERENCES

1. USAR, Appendix F.
2. USAR, Section VII-6.
3. USAR, Section XIV-5.3.3.
4. USAR, Section XIV-5.3.4.
5. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn.

The USAR, Appendix F, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Reactor Manual Control System).

This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refueling position one-rod-out interlock is explicitly assumed in the USAR analysis for the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

The refuel position one-rod-out interlock and adequate SDM(LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" prevent criticality by preventing withdrawal of more than one control rod. With one control rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

The refuel position one-rod-out interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

BASES

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of these channels.

APPLICABILITY

In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and the control rods (LCO 3.1.3, "Control Rod OPERABILITY") provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A.1 and A.2

With one or both channels of the refueling position one-rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refueling position one-rod-out interlock requires the reactor mode switch to be in Refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refueling position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Frequency of 12 hours is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. 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 CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The 7 day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator to control rods not fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

BASES

REFERENCES

1. USAR, Appendix F.
2. USAR, Section VII-6.
3. USAR, Section XIV-5.3.3.
4. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 21 ft above the top of the RPV flange. During refueling, this maintains a sufficient water level in the reactor vessel cavity. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a refueling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to well below the guidelines set forth in 10 CFR 100.11 (Ref. 3).

APPLICABLE SAFETY ANALYSES

During movement of fuel assemblies or handling of control rods, the water level in the RPV is an initial condition design parameter in the analysis of a refueling accident in containment postulated by Reference 1. A minimum water level of 21 ft allows a decontamination factor of 100 to be used in the accident analysis for halogens (Ref. 1). This relates to the assumption that 99% of the total halogens released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

Analysis of the refueling accident inside containment is described in Reference 1. With a minimum water level of 21 ft and a minimum decay time of 67 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated refueling accident is adequately captured by the water and that offsite doses are maintained within allowable limits (Ref. 3). The worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core loaded with irradiated fuel assemblies. The possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure