B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the reactor coolant pressure boundary (RCPB), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters, and equipment performance. The LSSS are defined in this Specification as the Allowable Values, which, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits, including Safety Limits (SLs), during Design Basis Accidents (DBAs).

The RPS, as described in the USAR, Section 7.2 (Ref. 1), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a reactor scram. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level; reactor vessel pressure; neutron flux; main steam line isolation valve position; turbine control valve (TCV) fast closure, trip oil pressure low; turbine stop valve (TSV) position; drywell pressure; and scram discharge volume (SDV) water level; as well as reactor mode switch in shutdown position and manual scram signals. There are at least four redundant sensor input signals from each of these parameters. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When a setpoint is exceeded, the channel output relay actuates, which then outputs an RPS trip signal to the trip logic.

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A1 and A2, B1 and B2), as described in Reference 1.

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BASES

BACKGROUND (continued)

The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

One dual-coil pilot scram valve is located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each pilot scram valve is solenoid operated, with the solenoids normally energized. The pilot scram valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either pilot scram valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both pilot scram valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the pilot scram valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 2, 3, and 4. The RPS initiates a reactor scram when monitored parameter values exceed the Allowable Values specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the RCPB, and the containment by minimizing the energy that must be absorbed following a LOCA.

RPS instrumentation satisfies Criterion 3 of Reference 5. Functions not specifically credited in the accident analysis

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual 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. 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., reactor vessel water level), 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of pilot scram valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES or other conditions specified in the Table that may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE to provide primary and diverse initiation signals.

The only MODES specified in Table 3.3.1.1-1 are MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No RPS Function is required in MODES 3 and 4, since all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. In MODE 5, control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all other control rods remain inserted, no RPS Function is required. In this condition, the required SDM (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS will occur. Under these conditions, the RPS function is not required to be OPERABLE.

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

1.a. Intermediate Range Monitor (IRM) Neutron Flux—Upscale

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection from the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Intermediate Range Monitor (IRM) Neutron Flux—Upscale (continued)

excursion (Ref. 6). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, a generic analysis has been performed (Ref. 7) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel enthalpy below the 170 cal/gm fuel failure threshold criterion.

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed.

The IRM System is divided into two groups of IRM channels, with four IRM channels inputting to each trip system. The analysis of Reference 7 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The analysis of Reference 7 has adequate conservatism to permit the IRM Allowable Value specified in Table 3.3.1.1-1.

The Intermediate Range Monitor Neutron Flux—Upscale Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System, the RWM, and the Rod Block Monitor provide protection against control rod withdrawal error events and the IRMs are not required. The IRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Intermediate Range Monitor—Inop

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM Operate-Calibrate switch is moved to any position other than "Operate," the detector polarizing voltage drops below a preset level, or a module interlock chain is broken, an inoperative trip signal will be received by the RPS unless the IRM is bypassed. Since only one IRM in each trip system may be bypassed, only one IRM in each RPS trip system may be inoperable without resulting in an RPS trip signal.

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.

Six channels of Intermediate Range Monitor—Inop with three channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

Since this Function is not assumed in the safety analysis, there is no Allowable Value for this Function.

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux—Upscale Function is required.

2.a. Average Power Range Monitor Neutron Flux—Upscale, Setdown

The APRM channels receive input signals from the local power range monitors (LPRM) within the reactor core, which provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux—Upscale, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux—Upscale, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux—Upscale Function because of the relative setpoints.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux—Upscale, Setdown (continued)

With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux—Upscale, Setdown Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux—Upscale, Setdown Function. However, this Function indirectly ensures that, before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

The APRM System is divided into four APRMs, each providing an input into both trip systems via the 2-Out-Of-4 Voter channels, Function 2.e. Each APRM inputs to all four 2-Out-Of-4 Voter channels, with each APRM input into a 2-Out-Of-4 Voter channel considered a channel. Thus, there are a total of 16 Average Power Range Monitor Neutron Flux—Upscale, Setdown channels, with eight channels per trip system and four channels per logic channel. The system is designed to allow one APRM to be bypassed (and since the APRM provides an input to all four 2-Out-Of-4 Voter channels, one channel in each logic channel is effectively bypassed). Any two APRM channels in a logic channel can cause the associated trip system to trip. Since each APRM inputs into both trip systems, this effectively means that when two APRMs provide a Neutron Flux—Upscale, Setdown signal, two channels in both logic channels in each trip system will trip, producing a scram. Twelve channels of Average Power Range Monitor Neutron Flux—Upscale, Setdown, with three channels per logic channel 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 20 LPRM inputs are required for each APRM, with at least three 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux—Upscale, Setdown (continued)

The Average Power Range Monitor Neutron Flux—Upscale, Setdown 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—Upscale Function provides protection against reactivity transients and the RWM and Rod Block Monitor protect against control rod withdrawal error events.

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale

The Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is digitally filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow, W, in percent of rated 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) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux—Upscale Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux—Upscale Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale Function setpoint is exceeded.

The APRM System is divided into four APRMs, each providing an input into both trip systems via the 2-Out-Of-4 Voter channels, Function 2.e. Each APRM inputs to all four

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale (continued)

2-Out-Of-4 Voter channels, with each APRM input into a 2-Out-Of-4 Voter channel considered a channel. Thus, there are a total of 16 Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale channels, with eight channels per trip system and four channels per logic channel. The system is designed to allow one APRM to be bypassed (and since the APRM provides an input to all four 2-Out-Of-4 Voter channels, one channel in each logic channel is effectively bypassed). Any two APRM channels in a logic channel can cause the associated trip system to trip. Since each APRM inputs into both trip systems, this effectively means that when two APRMs provide a Flow Biased Simulated Thermal Power—Upscale signal, two channels in both logic channels in each trip system will trip, producing a scram. Twelve channels of Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale, with three channels per logic channel in each trip system 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 20 LPRM inputs are required for each APRM, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM receives two flow signals from two flow transmitters, one from each reactor recirculation loop. The total recirculation drive flow signal is generated by the flow processing logic part of the APRM, by summing the flow calculated from these two flow transmitter signal inputs. Each APRM receives flow signals from different flow transmitters (a total of eight flow transmitters).

No specific safety analyses take direct credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale Function. Originally, the clamped Allowable Value was based on analyses that took credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale Function for the mitigation of the loss of feedwater heater event. However, the current methodology for this event is based on a steady state analysis that allows power to increase beyond the clamped Allowable Value. Therefore, applying a clamp is conservative. The THERMAL POWER time constant of ≤ 6.6 seconds is based on the fuel heat transfer dynamics and provides a signal that is proportional to the THERMAL POWER.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale (continued)

The Average Power Range Monitor Flow Biased Simulated Thermal Power—Upscale 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 Fixed Neutron Flux—Upscale

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 Fixed Neutron Flux—Upscale Function is capable of generating a trip signal to prevent fuel damage or excessive Reactor Coolant System pressure. For the overpressurization protection analysis of Reference 2, the Average Power Range Monitor Fixed Neutron Flux—Upscale Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 8) takes credit for the Average Power Range Monitor Fixed Neutron Flux—Upscale Function to terminate the CRDA.

The APRM System is divided into four APRMs, each providing an input into both trip systems via the 2-Out-Of-4 Voter channels, Function 2.e. Each APRM inputs to all four 2-Out-Of-4 Voter channels, with each APRM input into a 2-Out-Of-4 Voter channel considered a channel. Thus, there are a total of 16 Average Power Range Monitor Fixed Neutron Flux—Upscale channels, with eight channels per trip system and four channels per logic channel. The system is designed to allow one APRM to be bypassed (and since the APRM provides an input to all four 2-Out-Of-4 Voter channels, one channel in each logic channel is effectively bypassed). Any two APRM channels in a logic channel can cause the associated trip system to trip. Since each APRM inputs into both trip systems, this effectively means that when two APRMs provide a Fixed Neutron Flux—Upscale signal, two

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Average Power Range Monitor Fixed Neutron Flux—Upscale (continued)

channels in both logic channels in each trip system will trip, producing a scram. Twelve channels of Average Power Range Monitor Fixed Neutron Flux—Upscale with three channels per logic channel in each trip system 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 20 LPRM inputs are required for each APRM, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux—Upscale Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and Reactor Coolant System pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux—Upscale Function is assumed in the CRDA analysis (Ref. 8) that is applicable in MODE 2, the Average Power Range Monitor Neutron Flux—Upscale, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux—Upscale Function is not required in MODE 2.

2.d. Average Power Range Monitor—Inop

This signal provides assurance that a minimum number of APRM channels are OPERABLE. For any APRM, any time its function switch is moved out of the Operate position (i.e., to the inop position), a loss of power to the APRM occurs, the firmware/software watchdog timer has timed out, or the automatic self-test system detects a critical fault with the APRM, an inoperative trip signal will be sent to both trip systems via the 2-Out-Of-4 Voter channels, Function 2.e. Each APRM inputs to all four 2-Out-Of-4 Voter channels, with each APRM input into a 2-Out-Of-4 Voter channel considered a channel. Thus, there are a total of 16 Average Power Range Monitor—Inop channels, with eight channels per trip system and four channels per logic channel. The system is designed to allow one APRM to be bypassed (and since the APRM

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor—Inop (continued)

provides an input to all four 2-Out-Of-4 Voter channels, one channel per logic channel is effectively bypassed). Any two APRM channels in a logic channel can cause the associated trip system to trip. Since each APRM inputs into both trip systems, this effectively means that when two APRMs provide an Inop signal, two channels in both logic channels in each trip system will trip, producing a scram. 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.

Twelve channels of Average Power Range Monitor—Inop with three channels per logic channel 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.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the other APRM Functions are required.

2.e. Average Power Range Monitor 2-Out-Of-4 Voter

The 2-Out-Of-4 Voter Function provides the interface between the other APRM Functions and the RPS trip system logic, and as such, supports the safety analyses applicable to the other APRM Functions. Each APRM provides an input to all four 2-Out-Of-4 Voter channels (the input is common for Functions 2.a, 2.b, 2.c, and 2.d). The four 2-Out-Of-4 Voter channels are divided into two groups of two channels, with each group providing inputs into one RPS trip system (each channel inputs to one logic channel, similar to most other RPS instrumentation Functions). When two trip signals from any combination of APRM Functions 2.a, 2.b, 2.c, and 2.d are received (from different APRMs) by a 2-Out-Of-4 Voter channel, the 2-Out-Of-4 Voter channel provides a trip signal to its associated trip system. Any one 2-Out-Of-4 Voter channel can trip the associated trip system (i.e., a one-out-of-two logic). In addition, while each 2-Out-Of-4 Voter channel provides two inputs to its associated trip system, only one of the inputs is required for OPERABILITY.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.e. Average Power Range Monitor 2-Out-Of-4 Voter (continued)

Each 2-Out-Of-4 Voter channel also includes self-diagnostic functions. If any channel detects a critical fault in its own processing, a trip signal is provided to its associated trip system. Unlike the other APRM Functions, a bypass capability for the 2-Out-Of-4 Voter Function is not provided.

Four channels of the APRM 2-Out-Of-4 Voter Function 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.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the other APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure—High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure—High Function initiates a scram for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 2, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—Upscale signal, not the Reactor Vessel Steam Dome Pressure—High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Vessel Steam Dome Pressure—High (continued)

Four channels of Reactor Vessel Steam Dome 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 to be OPERABLE in MODES 1 and 2 since the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level—Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level—Low, Level 3 Function is a secondary scram signal to Drywell Pressure—High in the analysis of the recirculation line break (Ref. 3) but is assumed in the loss of feedwater flow event of Reference 4. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from four differential pressure transmitters 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.

Four channels of Reactor Vessel Water Level—Low, Level 3 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 Reactor Vessel Water Level—Low, Level 3 Allowable Value is selected to ensure that, for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS at RPV Water Level 1 will not be required.

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Reactor Vessel Water Level—Low, Level 3 (continued)

Vessel Water Level—Low Low, Level 2 and Low Low Low, Level 1 provide sufficient protection for level transients in all other MODES.

5. Main Steam Isolation Valve—Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the Nuclear Steam Supply System and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve—Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 2, the Average Power Range Monitor Fixed Neutron Flux—Upscale Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in Reference 4 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow). 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.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. Each MSIV has two position switches; one inputs to RPS trip system A while the other inputs to RPS trip system B. Thus, each RPS trip system receives an input from eight Main Steam Isolation Valve—Closure channels, each consisting of one position switch. The logic for the Main Steam Isolation Valve—Closure Function is arranged such that either the inboard or outboard valve on three or more of the main steam lines (MSLs) must close in order for a scram to occur. In addition, certain combinations of valves closed in two lines will result in a half-scram.

The Main Steam Isolation Valve—Closure Allowable Value is specified to ensure that a scram occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Main Steam Isolation Valve—Closure (continued)

Sixteen channels of the Main Steam Isolation Valve—Closure Function with eight channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 since, with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close. In MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

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 in the analysis of the recirculation line break. 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 transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

Four channels of Drywell Pressure—High 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 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.

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

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume 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 when the remaining

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a, b. Scram Discharge Volume Water Level—High (continued)

free volume is still sufficient to accommodate the water from a full core scram. However, even though the two types of Scram Discharge Volume Water Level—High Functions are an input to the RPS logic, 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 that 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 transmitters and trip units 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 transmitter and trip unit to each RPS logic channel. 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 the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level—High Function, with two channels of each type in each 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 is the primary scram signal for the turbine trip event analyzed in Reference 4. For this event, the reactor scram reduces the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Turbine Stop Valve—Closure (continued)

amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

Turbine Stop Valve—Closure signals are initiated by valve stem position switches at each stop valve. One switch is associated with each stop valve, and each switch provides two contacts. One of the two contacts provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve—Closure channels, each consisting of one valve stem position switch (which is common to a channel in the other RPS trip system) and a switch contact. The logic for the Turbine Stop Valve—Closure Function is such that three or more TSVs must be closed to produce a scram. In addition, certain combinations of two valves closed will result in a half scram.

This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is normally accomplished automatically by pressure transmitters 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.

Eight channels of Turbine Stop Valve—Closure, with four 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 the TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—Upscale Functions are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Turbine Control Valve Fast Closure, 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, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure switch associated with each control valve, the signal from each switch being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

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

Four channels of Turbine Control Valve Fast Closure, 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 ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—Upscale Functions are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Mode Switch—Shutdown Position

The Reactor Mode Switch—Shutdown Position Function provides signals, via the manual scram logic channels, that 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 single switch with four channels (one from each of the four independent banks of contacts), each of which inputs into one of the RPS logic channels.

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

Four channels of Reactor Mode Switch—Shutdown Position Function, with two channels in each 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 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.

11. Manual Scram

The Manual Scram switch and push button channels provide signals, via the manual scram logic channels, to each of the four RPS logic channels that 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 switch and push button (with two channels) for each of the four RPS logic channels. In order to cause a scram it is necessary that at least one switch and push button in each trip system be actuated.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

11. Manual Scram (continued)

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

Eight channels of Manual Scram with two switch and push buttons (two channels per switch and push button) in each trip system arranged in a one-out-of-two logic (i.e., both channels of a switch and push button must be actuated), 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.

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 (Refs. 10 and 11) to permit restoration of any inoperable required 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 (except for Functions 2.a, 2.b, 2.c, and 2.d) 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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. Alternately, 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 scram or recirculation pump trip (RPT)), 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.

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 References 10 and 11 for the 12 hour Completion Time, with the exception of Functions 2.a, 2.b, 2.c, and 2.d, as described below. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in References 10 and 11, which justified a 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, 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 or RPT), Condition D must be entered and its Required Action taken.

As noted, Condition B is not applicable for Functions 2.a, 2.b, 2.c, and 2.d. Since an inoperable APRM affects both trip systems (one channel per logic channel in each trip system is inoperable when an APRM is inoperable), Reference 11 evaluated the loss of one APRM and its effects for these Functions, and determined that a 12 hour Completion Time was acceptable. Therefore, when one required APRM is inoperable (which impacts both trip systems) only ACTION A is required to be entered.

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 Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For

(continued)

BASES

ACTIONS

C.1 (continued)

Functions 2.a, 2.b, 2.c, and 2.d (APRM Neutron Flux—Upscale, Setdown, APRM Flow Biased Simulated Thermal Power—Upscale, APRM Fixed Neutron Flux—Upscale, and APRM—Inop), this would require, for each Function, both trip systems to have two channels per logic channel, each 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 MSLs (not necessarily the same MSLs for both trip systems), 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 three channels, 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 Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner

(continued)

BASES

ACTIONS

E.1, F.1, and G.1 (continued)

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)."

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 RPS reliability analysis (Ref. 10) 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 RPS will trip when necessary.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.1 and SR 3.3.1.1.2

Performance of the CHANNEL CHECK once every 12 hours or every 24 hours, as applicable, 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 on 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 3.3.1.1.3

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. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. 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 3.3.1.1.7.

An allowance is provided that requires the SR to be performed only at ≥ 25% RTP because it is difficult to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.3 (continued)

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, APLHGR, and LHGR). At ≥ 25% RTP, the 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 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, for Functions 1.a and 1.b, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM 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). (The Manual Scram Function CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions Frequencies.)

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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 region without adequate neutron flux indication. This is required prior to fully withdrawing SRMs 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 (initiate 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. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block. The IRM/APRM and SRM/IRM overlaps are also acceptable if a 1/2 decade overlap exists.

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 channel(s) 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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.7

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 effective full power hours (EFPH) Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.8, SR 3.3.1.1.10, and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. For Function 2.b, the CHANNEL FUNCTIONAL TEST also includes the flow input function, excluding the flow transmitters. A Note is provided for SR 3.3.1.1.10 that requires the APRM SR for Function 2.a to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM Function 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 92 day Frequency of SR 3.3.1.1.8 is based on the reliability analysis of Reference 10. The 184 day Frequency of SR 3.3.1.1.10 is based on the reliability analysis of Reference 11. The 24 month Frequency of SR 3.3.1.1.12 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 24 month Frequency.

SR 3.3.1.1.9

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.9 (continued)

accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days for SR 3.3.1.1.9 is based on the reliability analysis of Reference 10.

SR 3.3.1.1.11 and SR 3.3.1.1.13

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. For Function 2.b, the CHANNEL CALIBRATION also includes the flow input function.

Note 1 to SR 3.3.1.1.13 states that neutron detectors are excluded from CHANNEL CALIBRATION 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 3.3.1.1.3) and the 1000 EFPH LPRM calibration against the TIPs (SR 3.3.1.1.7). A second Note is provided that requires the APRM and IRM SRs for Functions 1.a and 2.a 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 3.3.1.1.11 is based upon the assumption of a 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.13 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

The LOGIC SYSTEM FUNCTIONAL TEST (LSFT) demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function. In addition, for Function 2.e, the LSFT includes simulating APRM trip conditions at the APRM channel inputs to the 2-Out-Of-4 Voter channel to check all combinations of two tripped APRM channel inputs to the 2-Out-Of-4 Voter logic in the 2-Out-Of-4 Voter channels.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

SR 3.3.1.1.15

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 methodology are incorporated into the Allowable Value and the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure, where a first stage pressure of 136.4 psig is equivalent to 30% RTP), 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 setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.15 (continued)

inoperable. 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 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.16

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 12.

As noted (Note 1), the Function 2.e digital electronics are excluded. This is allowed since self-testing and calibration checks the time base of the digital electronics (confirmation of the time base is adequate to assure required response times are met). In addition, Note 2 states the response time of the sensors for Functions 3 and 4 may be assumed to be the design sensor response time and therefore, are excluded from the RPS RESPONSE TIME testing. This is allowed since the sensor response time is a small part of the overall RPS RESPONSE TIME (Ref. 13). Note 4 modifies the starting point of the RPS RESPONSE TIME test for Function 9, since this starting point (start of turbine control valve fast closure) corresponds with the safety analysis assumptions.

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 3 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 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 time degradation, but not channel failure, are infrequent.

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BASES (continued)

REFERENCES

1. USAR, Section 7.2.
2. USAR, Section 5.2.2 and Appendix A Section A.5.2.2.
3. USAR, Section 6.3.3.
4. USAR, Chapter 15 and Appendix A.
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section 15.4.1.
7. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
8. USAR, Section 15.4.9.
9. Letter, P. Check (NRC) 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. NEDC-32410-P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.
12. Technical Requirements Manual.
13. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and to determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to intermediate range monitor (IRM) overlap is demonstrated (as required by SR 3.3.1.1.5) and the IRMs are on Range 3, the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels (Ref. 1). Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation are provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

System (RPS) Instrumentation," Intermediate Range Monitor (IRM) Neutron Flux High and Average Power Range Monitor (APRM) Neutron Flux—High, Setdown Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

The SRMs have no safety function and are not assumed to function during any design basis accident or transient analysis. However, the SRMs provide the only on scale monitoring of neutron flux levels during startup and refueling. Therefore, they are being retained in the Technical Specifications.

LCO

During startup in MODE 2, three of the four SRM channels are required to be OPERABLE to monitor the reactor flux level prior to and during control rod withdrawal, to monitor subcritical multiplication and reactor criticality, and to monitor neutron flux level and reactor period until the flux level is sufficient to maintain the IRM on Range 3 or above. All channels but one are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core.

In MODES 3 and 4, with the reactor shut down, two SRM channels provide redundant monitoring of flux levels in the core.

In MODE 5, during a spiral offload or reload, an SRM outside the fueled region is not required to be OPERABLE, since it is not capable of monitoring neutron flux in the fueled region of the core. Thus, CORE ALTERATIONS are allowed in a quadrant with no OPERABLE SRM in an adjacent quadrant, provided the Table 3.3.1.2-1, footnote (b), requirement that the bundles being spiral reloaded or spiral offloaded are all in a single fueled region containing at least one OPERABLE SRM is met. Spiral reloading and offloading encompass reloading or offloading a cell on the edges of a continuous fueled region (the cell can be reloaded or offloaded in any sequence).

In nonspiral routine operations, two SRMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate

(continued)

BASES

LCO (continued)

coverage is provided by requiring one SRM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed and the other SRM to be OPERABLE in an adjacent quadrant containing fuel. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS.

Special movable detectors, according to Table 3.3.1.2-1, footnote (c), may be used in place of the normal SRM nuclear detectors. These special detectors must be connected to the normal SRM circuits in the NMS such that the applicable neutron flux indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2, and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.

APPLICABILITY

The SRMs are required to be OPERABLE in MODE 2 prior to the IRMs being on scale on Range 3, and MODES 3, 4, and 5, to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Providing that at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This is a reasonable time since there is adequate capability remaining to monitor the core, limited risk of an event during this time, and sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

capability. During this time, control rod withdrawal and power increase are not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap required by SR 3.3.1.1.5) and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to the inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2 with the IRMs on Range 2 or below, if the required number of SRMs is not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or more required SRM channels inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRM occurring during this time.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the capability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS 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. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity, given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Action (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each SRM Applicable MODE or other specified condition are found in the SRs column of Table 3.3.1.2-1.

SR 3.3.1.2.1 and SR 3.3.1.2.3

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to the same parameter indicated on other similar 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,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.1 and SR 3.3.1.2.3 (continued)

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 this 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, which include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

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. This ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.4 (continued)

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 quadrant, even with a control rod withdrawn the configuration will not be critical.

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. 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 7 day Frequency is reasonable, based on operating experience and on other Surveillances (such as a 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.5 and SR 3.3.1.2.6 (continued)

Verification of the signal to noise ratio also ensures that the detectors are inserted to a normal 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 fully withdrawn is assumed to be "noise" only. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to determine the signal to noise ratio. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the conditions necessary to determine the signal to noise ratio. To accomplish this, SR 3.3.1.2.5 is modified by a Note that states that the determination of signal to noise ratio 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 quadrant, even with a control rod withdrawn the configuration will not be critical.

The Note to SR 3.3.1.2.6 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 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 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.7 (continued)

The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) because they cannot readily be adjusted. The detectors are fission chambers that are 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 24 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

1. USAR, Section 7.7.1.7.2.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, logic circuitry, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the rod block monitor (RBM) provides protection for control rod withdrawal error events. During low power operations, control rod blocks from the rod worth minimizer (RWM) enforce specific control rod sequences designed to mitigate the consequences of the control rod drop accident (CRDA). During shutdown conditions, control rod blocks from the Reactor Mode Switch—Shutdown Position Function ensure that all control rods remain inserted to prevent inadvertent criticalities.

The purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations (Ref. 1). It is assumed to function to block further control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RBM supplies a trip signal to the Reactor Manual Control System (RMCS) to appropriately inhibit control rod withdrawal during power operation above the low power setpoint when a peripheral control rod is not selected. The RBM has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. One RBM channel inputs into one RMCS rod block circuit and the other RBM channel inputs into the second RMCS rod block circuit. The RBM channel signal is generated by averaging a set of local power range monitor (LPRM) signals. One RBM channel averages the signals from LPRM detectors at the A and C positions in the assigned LPRM assemblies, while the other RBM channel averages the signals from LPRM detectors at the B and D positions. Assignment of LPRM assemblies to be used in RBM averaging is controlled by the selection of control rods. The RBM is automatically bypassed and the output set to zero if a peripheral rod is selected or the APRM used to normalize the RBM reading is < 30% RTP. If any LPRM detector assigned to an RBM is bypassed, the computed average signal is automatically adjusted to compensate for the number of LPRM input signals. The minimum number of LPRM inputs required for each RBM channel to prevent an

(continued)

BASES

BACKGROUND (continued)

instrument inoperative alarm is four when using four LPRM assemblies, three when using three LPRM assemblies, and two when using two LPRM assemblies. Each RBM also receives a recirculation loop flow signal from the reference APRM.

When a control rod is selected, the gain of each RBM channel output is normalized to a reference APRM. The gain setting is held constant during the movement of that particular control rod to provide an indication of the change in the relative local power level. If the indicated power increases above the preset limit, a rod block will occur. In addition, to preclude rod movement with an inoperable RBM, a downscale trip and an inoperable trip are provided.

The purpose of the RWM is to control rod patterns during startup and shutdown, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. A prescribed control rod sequence is stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). The RWM is a single channel system that provides input into one RMCS rod block circuit.

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents inadvertent criticality as the result of a control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, each inputting into a separate RMCS rod block circuit. A rod block in either RMCS circuit will provide a control rod block to all control rods.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 3. The cycle-specific analysis considers the continuous withdrawal of the maximum worth control rod at its maximum drive speed from the reactor, which is operating at rated power with a control rod pattern that results in the core being placed on thermal design limits. The condition is analyzed to ensure that the results obtained are conservative; the approach also serves to demonstrate the function of the RBM.

The RBM Function satisfies Criterion 3 of Reference 3.

Two channels of the RBM are required to be OPERABLE, with their setpoints within the appropriate Allowable Values to ensure that no single instrument failure can preclude a rod block from this Function. The actual setpoints are calibrated consistent with applicable setpoint methodology.

Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values 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 power), 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The RBM is assumed to mitigate the consequences of an RWE event when operating ≥ 30% RTP and a peripheral control rod is not selected. Below this power level, or if a peripheral control rod is selected, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Ref. 4).

2. Rod Worth Minimizer

The RWM enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in Reference 5. The BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control."

The RWM Function satisfies Criterion 3 of Reference 3.

Since the RWM is a system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. 6). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% RTP. When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 5). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Rod Worth Minimizer (continued)

cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

3. Reactor Mode Switch—Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch—Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch—Shutdown Position Function satisfies Criterion 3 of Reference 3.

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODES 3 and 4, and MODE 5 when the reactor mode switch is in the shutdown position), no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") provides the required control rod withdrawal blocks.

ACTIONS

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this

(continued)

BASES

ACTIONS

A.1 (continued)

reason, Required Action A.1 requires restoration of the inoperable channel to OPERABLE status. The Completion Time of 24 hours is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

B.1

If Required Action A.1 is not met and the associated Completion Time has expired, the inoperable channel must be placed in trip within 1 hour. If both RBM channels are inoperable, the RBM is not capable of performing its intended function; thus, one channel must also be placed in trip. This initiates a control rod withdrawal block, thereby ensuring that the RBM function is met.

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

C.1, C.2.1.1, C.2.1.2, and C.2.2

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM during withdrawal of one or more of the first 12 control rods was not performed in the last calendar year (i.e., the current calendar year). These requirements minimize the number of reactor startups initiated with the RWM inoperable. Required Actions C.2.1.1 and C.2.1.2 require verification of these conditions by review of plant logs and control room indications. Once Required Action C.2.1.1 or C.2.1.2 is satisfactorily completed, control rod withdrawal may proceed in accordance with the restrictions imposed by Required Action C.2.2. Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the

(continued)

BASES

ACTIONS

C.1, C.2.1.1, C.2.1.2, and C.2.2 (continued)

prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). The RWM may be bypassed under these conditions to allow continued operations. In addition, Required Actions of LCO 3.1.3 and LCO 3.1.6 may require bypassing the RWM, during which time the RWM must be considered inoperable with Condition C entered and its Required Actions taken.

D.1

With the RWM inoperable during a reactor shutdown, the operator is still capable of enforcing the prescribed control rod sequence. Required Action D.1 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). The RWM may be bypassed under these conditions to allow the reactor shutdown to continue.

E.1 and E.2

With one Reactor Mode Switch—Shutdown Position control rod withdrawal block channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod withdrawal block function. However, since the Required Actions are consistent with the normal action of an OPERABLE Reactor Mode Switch—Shutdown Position Function (i.e., maintaining all control rods inserted), there is no distinction between having one or two channels inoperable.

In both cases (one or both channels inoperable), suspending all control rod withdrawal and initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies will ensure that the core is subcritical with adequate SDM ensured by LCO 3.1.1. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are therefore not

(continued)

ACTIONS

E.1 and E.2 (continued)

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 Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a second Note to indicate that when an RBM 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 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. 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 a control rod block will be initiated when necessary.

SR 3.3.2.1.1 and SR 3.3.2.1.2

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. The CHANNEL FUNCTIONAL TEST for the RWM is performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs and by 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 3.3.2.1.1 is not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2, and SR 3.3.2.1.2 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 (and if entering during a shutdown, concurrent power reduction to ≤ 10% RTP) for SR 3.3.2.1.1, and THERMAL POWER reduction to ≤ 10% RTP in MODE 1 for SR 3.3.2.1.2, to perform the required Surveillances if the 92 day Frequency is not met per SR 3.0.2. The 1 hour

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1 and SR 3.3.2.1.2 (continued)

allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. Operating experience has shown that these components usually pass the Surveillance when performed at the 92 day Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the entire channel will perform the intended function. It includes the Reactor Manual Control Multiplexing System input.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 184 days is based on the analysis in Reference 8.

SR 3.3.2.1.4

The RBM is automatically bypassed when power is below a specified value or if a peripheral control rod is selected. The power level is determined from the APRM signals input to each RBM channel. The automatic bypass setpoint must be verified periodically to be < 30% RTP. In addition, it must also be verified that when ≥ 30% RTP, the RBM is not bypassed when a control rod that is not a peripheral control rod is selected (only one non-peripheral control rod is required to be verified). If any bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the APRM channel can be placed in the conservative condition to enable the RBM. 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 3.3.1.1.3 and SR 3.3.1.1.7. The 24 month Frequency is based on the analysis in Reference 8.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.5

The RWM is automatically bypassed when power is above a specified value. The power level is determined from steam flow signals. The automatic bypass setpoint must be verified periodically to be > 10% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the Allowable Value and the actual setpoint. 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 3.3.2.1.6

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch—Shutdown Position Function to ensure that the entire channel will perform the intended function. 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 24 month Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operaitng experience and in consideration of providing a reasonable time in which to complete the SRs.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.7

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 3.3.1.1.3 and SR 3.3.1.1.7.

The Frequency is based on the analysis in Reference 8.

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.

REFERENCES

1. USAR, Section 7.7.1.7.
2. USAR, Section 7.7.1.3.
3. 10 CFR 50.36(c)(2)(ii).
4. USAR, Section 15.4.2.3.
5. USAR, Section 15.4.9.
6. 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.

(continued)

BASES

REFERENCES (continued)

7. GENE-770-06-1-A, "Addendum To Bases For Changes To Surveillance Test Intervals And Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," December 1992.

8. NEDC-32410-P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater System and Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The Feedwater System and Main Turbine High Water Level Trip Instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level, Level 8 reference point, causing the trip of the three feedwater pumps and the main turbine.

Reactor Vessel Water Level—High, Level 8 signals are provided by differential pressure transmitters 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 in the reactor vessel (variable leg). Three channels of Reactor Vessel Water Level—High, Level 8 instrumentation are provided as input to a two-out-of-three initiation logic that trips the three feedwater pumps and the main turbine. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a feedwater pump and main turbine trip signal to the trip logic.

A trip of the feedwater pumps limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the stop valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The Feedwater System and Main Turbine High Water Level Trip Instrumentation is assumed to be capable of providing a feedwater pump and main turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1) and in other design basis events in Reference 2. The Level 8 trip indirectly initiates a reactor scram from the main turbine trip (above 30% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Feedwater System and Main Turbine High Water Level Trip Instrumentation satisfies Criterion 3 of Reference 3.

LCO

The LCO requires three channels of the Reactor Vessel Water Level—High, Level 8 instrumentation to be OPERABLE to ensure that no single instrument failure will prevent the feedwater pumps and main turbine trip on a valid Level 8 signal. Two of the three channels are needed to provide trip signals in order for the feedwater pumps and main turbine trips to occur. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.3. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. 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 successive 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., reactor vessel water level), 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively

(continued)

BASES

LCO (continued)	derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.
APPLICABILITY	The Feedwater System and Main Turbine High Water Level Trip Instrumentation is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "Average Planar Linear Heat Generation Rate (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.
ACTIONS	A Note has been provided to modify the ACTIONS related to Feedwater System and Main Turbine High Water Level Trip 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 Feedwater System and Main Turbine High Water Level Trip 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 Feedwater System and Main Turbine High Water Level Trip Instrumentation channel.

A.1

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status

(continued)

BASES

ACTIONS

A.1 (continued)

within the Completion Time, the channel must be 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, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in a feedwater pump or main turbine trip), Condition C must be entered and its Required Action taken.

The Completion Time of 7 days is based on the low probability of the event occurring coincident with a single failure in a remaining OPERABLE channel.

B.1

With two or more channels inoperable, the Feedwater System and Main Turbine High Water Level Trip Instrumentation cannot perform its design function (feedwater system and main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which feedwater system and main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient channels are OPERABLE or in trip such that the feedwater system and main turbine high water level trip logic will generate a trip signal on a valid signal. This requires two channels to each be OPERABLE or in trip. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition C must be entered and its Required Action taken.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of Feedwater System and Main Turbine High Water Level Trip Instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With a channel not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the Feedwater System and Main Turbine High Water Level Trip Instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. Alternately, if a channel is inoperable solely due to an inoperable feedwater pump breaker, the affected feedwater pump breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 Function maintains feedwater system and main turbine high water level 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. 4) assumption that 6 hours is 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 feedwater pumps and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.2.1 (continued)

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 limits.

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 the channels required by the LCO.

SR 3.3.2.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. 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 analysis (Ref. 4).

SR 3.3.2.2.3

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 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater pump breakers and main turbine stop valves 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 a main turbine stop valve or feedwater pump breaker is incapable of operating, the associated instrumentation would also be inoperable. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

REFERENCES

1. USAR, Sections 15.1.2 and A.15.1.2.
2. USAR, Sections 15.1 and 15.3.
3. 10 CFR 50.36(c)(2)(ii).
4. GENE-770-06-1-A, "Bases For Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display, in the control room, plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events. The instruments that monitor these variables are designated as Type A, Category I, and non-Type A, Category I in accordance with Regulatory Guide 1.97 (Ref. 1).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A, variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (EOP). These variables are restricted to preplanned actions for the primary success path of Design Basis Accidents (DBAs) (e.g., loss of coolant accident (LOCA)); and
- Take the specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for safety systems to accomplish their safety function.

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine whether a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to obtain an estimate of the magnitude of any impending threat.

The plant specific Regulatory Guide 1.97 analysis (Ref. 2) documents the process that identified Type A and Category I, non-Type A, variables.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of Reference 3. Category I, non-Type A, instrumentation is retained in the Technical Specifications (TS) because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires two OPERABLE channels for most of the Functions to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following an accident. Furthermore, providing two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exceptions of the two channel requirement are the primary containment isolation valve (PCIV) position and the suppression pool water temperature. For the PCIV position, the important information is the status of the primary containment penetrations. The LCO requires one position indicator for each active (e.g., automatic) PCIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of passive valve or via system boundary status. If a normally active PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for closed and deactivated valves is not required to be OPERABLE. For the suppression pool water temperature, two channels are required for each quadrant. This is

(continued)

BASES

LCO (continued)

necessary since heat addition to one quadrant may not be readily discernable in another quadrant.

Listed below is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1.

1. Reactor Vessel Pressure

Reactor vessel pressure is a Type A and Category I variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig monitor pressure. Wide range recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

2.a, 2.b. Reactor Vessel Water Level

Reactor vessel water level is a Type A and Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. Two different range channels, wide range and fuel zone range, provide the PAM Reactor Vessel Water Level Function. The wide range water level channels measure from approximately 13 inches above the top of active fuel to approximately 223 inches above the top of active fuel while the fuel zone range channels measure from approximately 147 inches below the top of active fuel to approximately 53 inches above the top of active fuel. Wide range water level is measured by two independent differential pressure transmitters. The output from these channels is recorded on two independent pen recorders. Fuel zone range level is measured by two independent differential pressure transmitters. The output of one transmitter is directed to an indicator while the other output is directed to a recorder. These instruments are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

The reactor vessel water level instruments are uncompensated for variation in reactor water density and are calibrated to be most accurate at a specific vessel pressure and temperature. The wide range instruments are calibrated to

(continued)

BASES

LCO

2.a, 2.b. Reactor Vessel Water Level (continued)

be accurate at the normal operating pressure and temperature. The fuel zone range instruments are calibrated to be accurate at post-DBA LOCA pressure and temperature.

3.a, 3.b. Suppression Pool Water Level

Suppression pool water level is a Category I variable provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. Two different range channels provide the PAM Suppression Pool Water Level Function. The wide range and narrow range suppression pool water level measurement provides the operator with sufficient information to assess the status of the RCPB and to assess the status of the water supply to the ECCS. The wide range water level indicators monitor the suppression pool level from 2 ft. above the bottom of the downcomers to near the top of the pool (192 ft. to 217 ft.), while the narrow range water level indicators monitor the water level around its normal level (198 ft. to 202 ft.). Two wide range suppression pool water level signals are transmitted from separate transmitters and are continuously displayed on a recorder or an indicator in the control room. Two narrow range suppression pool water level signals are transmitted from separate transmitters and are continuously displayed on two independent indicators in the control room. These instruments are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

4.a, 4.b. Drywell Pressure

Drywell pressure is a Type A and Category I variable provided to detect a breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Two different range channels provide the PAM Drywell Pressure Function. The wide range instruments measure from 0 psig to 150 psig while the narrow range instruments monitor between -5 psig and +5 psig. The wide range drywell pressure signals are transmitted from separate pressure transmitters and are continuously displayed on a control room recorder and indicator. Two narrow range drywell pressure signals

(continued)

BASES

LCO

4.a. 4.b. Drywell Pressure (continued)

are transmitted from separate transmitters and are continuously displayed on independent recorders or indicators in the control room. These recorders and indicators are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5. Drywell Radiation (High Range)

Drywell area radiation (high range) is a Category I variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Four detectors are located inside the drywell that have a range from 10^0 R/hr to 10^7 R/hr. These monitors respond to gamma radiation of 100 KeV as required by Regulatory Guide 1.97 to see the Xe-133 gases. These radiation monitors display on recorders located in the control room. However, only two of the radiation monitors/recorders are required to be OPERABLE (one per division). Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

6. Drywell Air Temperature

Drywell Air Temperature is a Type A and Category I variable provided to ensure containment integrity is maintained and to determine whether or not a drywell spray initiation or a reactor depressurization is required. Drywell air temperature is monitored in the control room from twelve separate temperature sensors whose outputs are directed to four recorders (three sensors input to each recorder). The range is from 50°F to 350°F. These instruments are the primary indication used by the operator during an accident. The two divisionalized recorders and six sensors constitute a channel. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

(continued)

BASES

LCO (continued)

7. Suppression Chamber Pressure

Suppression chamber pressure is a Category I variable provided to determine whether or not reactor depressurization or venting of the primary containment will be required. Suppression chamber pressure is monitored in the control room from two separate pressure transmitters and is continuously displayed on a recorder and an indicator. The range is from 0 psig to 150 psig. These instruments are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

8. Primary Containment Isolation Valve (PCIV) Position

PCIV (excluding check valves) position is a Category I variable provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to verify redundantly the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration is not required to be OPERABLE (Note (a)).

The indication for each PCIV is provided at the valve controls in the control room. Each indication consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM Specification deals specifically with this portion of the instrumentation channel.

(continued)

BASES

LCO (continued)

9, 10. Drywell Hydrogen and Oxygen Concentration Analyzer

Drywell hydrogen and oxygen analyzers are Type A and Category I instruments provided to detect high hydrogen or oxygen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions.

Hydrogen and oxygen concentrations are each measured by two independent analyzers and continuously monitored in the control room. Each Function is monitored by one indicator and one recorder. The analyzers are capable of operating from 12 psia to 45 psig. The range of the drywell hydrogen analyzer is from 0% to 30% while the range of the oxygen analyzer is from 0% to 10%. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

11. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A and Category I variable provided to detect a condition that could potentially lead to containment breach, and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature instrumentation allows operators to detect trends in suppression pool water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool. Eight temperature sensors are arranged in four groups of two independent and redundant channels, located such that there is one group of sensors in each quadrant of the suppression pool. The range of the suppression pool water temperature channels is from 50°F to 250°F.

Thus, four groups of sensors are sufficient to monitor the bulk average temperature of the suppression pool. The outputs for the PAM sensors are monitored on an indicator and two recorders in the control room. One group of sensors provides input only to an indicator while the other group of sensors provides input to both an indicator and two recorders, but only the two recorders are required for this group. Both the indicator and the two recorders must be OPERABLE to furnish two channels of PAM indication for each quadrant of the suppression pool. A selector switch is

(continued)

BASES

LCO

<u>11. Suppression Pool Water Temperature</u> (continued)

available for the indicator and a different pen recorder for each sensor is available for the two recorders so that each sensor can be monitored. The indicator and recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

APPLICABILITY

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

ACTIONS

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

A Note has also been provided to modify the ACTIONS related to PAM 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 PAM instrumentation channels provide appropriate compensatory measures for separate inoperable functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

(continued)

BASES

ACTIONS (continued)

A.1

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

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions in accordance with Specification 5.6.6, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This Required Action is appropriate in lieu of a shutdown requirement since another OPERABLE channel is monitoring the Function, an alternate method of monitoring is available, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

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

(continued)

BASES

ACTIONS (continued)

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

For the majority of Functions in Table 3.3.3.1-1, if the Required Action and associated Completion Time of Condition C is not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours.

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

F.1

Since alternate means of monitoring drywell radiation have been developed and tested, the Required Action is not to shut down the plant but rather to follow the directions of Specification 5.6.6. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1, except where identified in the SR.

The Surveillances are modified by a second Note to indicate that when a channel is placed in an inoperable status solely

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other required channel in the associated Function is OPERABLE. 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. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary.

SR 3.3.3.1.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar plant instruments located in the drywell. For Function 8, the CHANNEL CHECK shall consist of verifying the valve is at its correct position by checking as appropriate its red, green, or analog indication in the control room.

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1 (continued)

CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the channels required by the LCO.

SR 3.3.3.1.2 and SR 3.3.3.1.3

A CHANNEL CALIBRATION is performed every 92 days for Functions 9 and 10 and every 24 months for all other Functions. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. For Function 5, the CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, excluding the detector, for range decades ≥ 10 R/hour and a one point calibration check of the detector with an installed or portable gamma source for the range decade < 10 R/hour. For Function 8, the CHANNEL CALIBRATION shall consist of a position verification using the criteria specified in the Inservice Testing Program. For Function 9, the CHANNEL CALIBRATION shall consist of a calibration at one volume percent and four volume percent hydrogen (balance nitrogen). The 92 day and 24 month Frequencies are based on operating experience and engineering judgement.

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, May 1983.
2. USAR, Section 7.5.2.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.3.2 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room (Ref. 1). This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the Reactor Core Isolation Cooling (RCIC) System, the safety/relief valves, and the Residual Heat Removal System can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the RCIC System and the ability to operate shutdown cooling from outside the control room allow extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the plant in MODE 3. All controls and necessary transfer switches are located at the remote shutdown panel. The plant is in MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it meets Criterion 4 of Reference 3.

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Reference 4.

The controls, instrumentation, and transfer switches are those required for:

- Reactor pressure vessel (RPV) pressure control;
- Decay heat removal;
- RPV inventory control;
- Service Water System; and
- Nitrogen supply to ADS accumulators.

The Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown function are OPERABLE.

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

APPLICABILITY

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

This LCO is not applicable in MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore

(continued)

BASES

APPLICABILITY (continued)

necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, the LCO does not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

A Note is included that excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a plant shutdown. This exception is acceptable due to the low probability of an event requiring this system.

Note 2 has been provided to modify the ACTIONS related to Remote Shutdown System Functions. 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 Remote Shutdown System Functions provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable Remote Shutdown System Function.

<u>A.1</u>

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System is inoperable. This includes any Function listed in Reference 4, as well as the control and transfer switches. The Required Action is to restore the Function (both divisions, if applicable) to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

<u>B.1</u>

If the Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status,

(continued)

BASES

ACTIONS

B.1 (continued)

the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when an instrument 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. 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. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly operating the associated equipment, when necessary.

SR 3.3.3.2.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the 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 sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1 (continued)

The Frequency is based upon operating experience that demonstrates channel failure is rare.

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Remote Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the remote shutdown panel. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel. Operating experience demonstrates that Remote Shutdown System control channels usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.3.2.3

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

The 24 month Frequency is based upon operating experience and engineering judgment, and is consistent with the typical industry refueling cycle.

REFERENCES

1. USAR, Section 7.4.2.4.
2. 10 CFR 50, Appendix A, GDC 19.
3. 10 CFR 50.36(c)(2)(ii).
4. Technical Requirements Manual.

B 3.3 INSTRUMENTATION

B 3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

BASES

BACKGROUND

The EOC-RPT instrumentation initiates a recirculation pump trip (RPT), if operating in fast speed, to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to the core thermal MCPR Safety Limit (SL).

The need for the additional negative reactivity in excess of that normally inserted on a scram reflects end of cycle reactivity considerations. Flux shapes at the end of cycle are such that the control rods may not be able to ensure that thermal limits are maintained by inserting sufficient negative reactivity during the first few feet of rod travel upon a scram caused by Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure—Low, or Turbine Stop Valve (TSV)—Closure. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity at a faster rate than the control rods can add negative reactivity.

The EOC-RPT instrumentation as described in Reference 1 is comprised of sensors that detect initiation of closure of the TSVs, or fast closure of the TCVs, combined with relays, logic circuits, and fast acting circuit breakers that interrupt the power to each of the recirculation pump motors. The channels include electronic equipment (e.g., trip switches) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an EOC-RPT signal to the trip logic. When the EOC-RPT breakers (3A, 3B, 4A, and 4B; the fast speed breakers) trip open, the recirculation pumps coast down under their own inertia, the LFMG starts, and low frequency breakers 1A, 1B, 2A, and 2B close automatically on a motor speed interlock to operate the recirculation pumps on low speed (although the recirculation pump start in low speed is not part of the EOC-RPT Instrumentation safety function). The EOC-RPT has two identical trip systems, either of which can actuate an RPT.

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TSV—Closure or two TCV Fast Closure, Trip Oil Pressure—Low signals are required for a

(continued)

BASES

BACKGROUND (continued)	trip system to actuate. If either trip system actuates, both recirculation pumps, if operating in fast speed, will trip. There are two EOC-RPT breakers in series per recirculation pump. One trip system trips one of the two EOC-RPT breakers for each recirculation pump and the second trip system trips the other EOC-RPT breaker for each recirculation pump.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The TSV—Closure and the TCV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps, if operating in fast speed, in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux and pressurization transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in Reference 2. To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps, if operating in fast speed, after initiation of initial closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT as specified in the COLR are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when THERMAL POWER, as sensed by turbine first stage pressure, is < 30% RTP. EOC-RPT instrumentation satisfies Criterion 3 of Reference 3. The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure 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. 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., TCV electrohydraulic control (EHC) pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip switches) 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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

Alternately, since this instrumentation protects against a MCPR SL violation with the instrumentation inoperable, modifications to the MCPR limits (LCO 3.2.2) may be applied to allow this LCO to be met. The MCPR limit for the condition EOC-RPT inoperable is specified in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Stop Valve—Closure

Closure of the TSVs and a main turbine trip result in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TSV—Closure, in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring the MCPR SL is not exceeded during the worst case transient.

Closure of the TSVs is determined by measuring the position of each stop valve. There is one valve stem position switch associated with each stop valve, and the signal from each switch is assigned to a separate trip channel. The logic for the TSV—Closure Function is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function. Four channels of TSV—Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV—Closure Allowable Value is selected to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 30% RTP with any recirculating pump in fast speed. Below 30% RTP or with the recirculation in slow speed, the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor (APRM) Fixed Neutron Flux—Upscale Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

TCV Fast Closure, Trip Oil Pressure—Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure—Low in anticipation of the transients that would result from the closure of these

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

TCV Fast Closure, Trip Oil Pressure—Low (continued)

valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the EHC fluid pressure at each control valve. There is one pressure switch associated with each control valve, and the signal from each switch is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure—Low Function is such that two or more TCVs must be closed (pressure switch trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

This protection is required consistent with the analysis, whenever the THERMAL POWER is ≥ 30% RTP with any recirculation pump in fast speed. Below 30% RTP or with the recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure—High and the APRM Fixed Neutron Flux—Upscale Functions of the RPS are adequate to maintain the necessary safety margins. The turbine first stage pressure/reactor power relationship for the setpoint of the automatic enable is identical to that described for TSV closure.

ACTIONS

A Note has been provided to modify the ACTIONS related to EOC-RPT 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

(continued)

BASES

ACTIONS (continued)

inoperable EOC-RPT 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 EOC-RPT instrumentation channel.

A.1 and A.2

With one or more required channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Action B.1 and B.2 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide 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 an EOC-RPT, 72 hours is allowed to restore the inoperable channels (Required Action A.1) or apply the EOC-RPT inoperable MCPR limit. Alternately, the inoperable channels may be placed in trip (Required Action A.2) since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted in Required Action A.2, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition C must be entered and its Required Actions taken.

B.1 and B.2

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Function not maintaining EOC-RPT trip capability. A Function is considered to be maintaining EOC-RPT trip capability when sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps, if operating in fast speed, can be tripped. This requires two channels of the Function, in the same trip system, to each be OPERABLE or in trip, and the associated EOC-RPT breakers to be OPERABLE or in trip. Alternatively, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2, Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 30% RTP within 4 hours. Alternately, the associated recirculation pump fast speed breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 30% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 EOC-RPT 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

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BASES

SURVEILLANCE REQUIREMENTS (continued)

entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) 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 recirculation pumps will trip when necessary.

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. 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 analysis (Ref. 4).

SR 3.3.4.1.2

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 24 month calibration interval, in the determination of the magnitude of equipment drift in the setpoint analysis and engineering judgment.

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.3 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month Frequency.

SR 3.3.4.1.4

This SR ensures that an EOC-RPT initiated from the TSV—Closure and TCV 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 first stage pressure, where a first stage pressure of 136.4 psig is equivalent of 30% RTP), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER ≥ 30% RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP either due to open main turbine bypass valves or other reasons), the affected TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. 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 considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.5

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 5.

A Note to the Surveillance states that breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. This is allowed since the arc suppression time is short and does not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, the 24 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 that cause serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.4.1.6

This SR ensures that the EOC-RPT breaker arc suppression time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. The 60 month Frequency of the testing is based on the difficulty of performing the test and the reliability of the circuit breakers.

REFERENCES

1. USAR, Section 7.6.1.5.
2. USAR, Sections 15.2.2, 15.2.3, and 15.2.5.
3. 10 CFR 50.36(c)(2)(ii).
4. GENE-770-06-1-A, "Bases For Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," December 1992.
5. USAR, Table 7.6-7.

B 3.3 INSTRUMENTATION

B 3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND

The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not but should occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level—Low Low, Level 2 or Reactor Vessel Steam Dome Pressure—High setpoint is reached, the recirculation pump motor breakers trip.

The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability, circuit breakers, and switches that are necessary to cause initiation of a recirculation pump trip. The channels include electronic equipment (e.g., analog trip modules) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure—High and two channels of Reactor Vessel Water Level—Low Low, Level 2, in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Water Level—Low Low, Level 2 or two Reactor Vessel Steam Dome Pressure—High signals are needed to trip a trip system. When both Reactor Vessel Water Level—Low Low, Level 2 setpoints are reached, the outputs of the channels in a trip system are combined in a logic so that either trip system will trip both recirculation pumps (by tripping the respective fast speed and low frequency motor generator (LFMG) breakers). When both Reactor Vessel Steam Dome Pressure—High setpoints are reached, the outputs of the channels in a trip system are combined in a logic so that either trip system will trip both recirculation pumps fast speed breakers and send a start signal to the LFMGs (although this start signal is not required as part of the ATWS-RPT System OPERABILITY). If, after approximately 25 seconds, both Reactor Vessel Steam Dome Pressure—High signals are still high and the associated APRM signals

(continued)

BASES

BACKGROUND (continued)

are not downscale (approximately ≤ 4% RTP), the LFMG breakers for both recirculation pumps will be tripped. In addition, the required APRM input to each Reactor Vessel Steam Dome Pressure—High channel must be from separate APRMs.

There are two fast speed motor breakers and two LFMG breakers provided for each of the two recirculation pumps for a total of eight breakers. The output of each trip system will trip one fast speed breaker and both LFMG breakers (the input and output breakers) for each recirculation pump. However, for the LFMG breaker trip portion of each trip system, only one LFMG breaker (either input or output) per recirculation pump is required to be tripped for ATWS-RPT System OPERABILITY, with each trip system required to trip a different LFMG breaker. Furthermore, the combination of trip system inputs for one LFMG set may be different for the other LFMG set.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ATWS-RPT is not assumed to mitigate any accident or transient in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation meets Criterion 4 of Reference 2.

The OPERABILITY of the ATWS-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.2.5. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump fast speed breakers and the LFMG input and output breakers.

Allowable Values are specified for each ATWS-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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., analog trip module) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the ATWS analysis (Ref. 3). The Allowable Values are derived from the analytic limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The individual Functions are required to be OPERABLE in MODE 1 to protect against common mode failures of the Reactor Protection System by providing a diverse trip to mitigate the consequences of a postulated ATWS event. The Reactor Vessel Steam Dome Pressure—High and Reactor Vessel Water Level—Low Low, Level 2 Functions are required to be OPERABLE in MODE 1, since the reactor is producing significant power and the recirculation system could be at high flow. During this MODE, the potential exists for pressure increases or low water level, assuming an ATWS event. In MODE 2, the reactor is at low power and the recirculation system is at low flow; thus, the potential is low for a pressure increase or low water level, assuming an ATWS event. Therefore, the ATWS-RPT is not necessary. In MODES 3 and 4, the reactor is shut down with all control rods inserted; thus, an ATWS event is not significant and the possibility of a significant pressure increase or low water level is negligible. In MODE 5, the one-rod-out interlock ensures the reactor remains subcritical; thus, an ATWS event is not significant. In addition, the reactor pressure vessel (RPV) head is not fully tensioned and no pressure transient threat to the reactor coolant pressure boundary (RCPB) exists.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

a. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the ATWS-RPT System is initiated at Level 2 to aid in maintaining level above the top of the active fuel. The reduction of core flow reduces the neutron flux and THERMAL POWER and, therefore, the rate of coolant boiloff.

Reactor vessel water level signals are initiated from four differential pressure transmitters 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.

Four channels of Reactor Vessel Level—Low Low, Level 2, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel Water Level—Low Low, Level 2, Allowable Value is chosen so that the system will not initiate after a Level 3 scram with feedwater still available, and for convenience with the reactor core isolation cooling (RCIC) initiation.

b. Reactor Vessel Steam Dome Pressure—High

Excessively high RPV pressure may rupture the RCPB. An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This increases neutron flux and THERMAL POWER, which could potentially result in fuel failure and RPV overpressurization. The Reactor Vessel Steam Dome Pressure—High Function initiates an RPT for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power generation. For the overpressurization event, the RPT aids in the mitigation of the ATWS event and, along with the safety/relief valves (S/RVs), limits the peak RPV pressure to less than the ASME Section III Code Service Level C limits (1500 psig).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Reactor Vessel Steam Dome Pressure—High (continued)

The Reactor Vessel Steam Dome Pressure—High signals are initiated from four pressure transmitters that monitor reactor vessel steam dome pressure. Four channels of Reactor Vessel Steam Dome Pressure—High, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel Steam Dome Pressure—High Allowable Value is chosen to provide an adequate margin to the ASME Section III Code Service Level C allowable Reactor Coolant System pressure.

ACTIONS

A Note has been provided to modify the ACTIONS related to ATWS-RPT 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 ATWS-RPT 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 ATWS-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT trip capability for each Function maintained (refer to Required Action B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desirable to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D 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 the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system to each be OPERABLE or in trip, and the corresponding breakers (one fast speed and one LFMG per pump) to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and the fact that one Function is still maintaining ATWS-RPT trip capability.

(continued)

BASES

ACTIONS (continued)

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action B.1, above.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

D.1 and D.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours (Required Action D.2). Alternately, the associated recirculation pump breaker(s) may be removed from service since this performs the intended Function of the instrumentation (Required Action D.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove recirculation pump breaker(s) from service in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 ATWS-RPT 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. 4) 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 recirculation pumps will trip when necessary.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.1

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

SR 3.3.4.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. 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 4.

SR 3.3.4.2.3

Calibration of analog trip modules provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.3 (continued)

conservative than the Allowable Value specified in SR 3.3.4.2.5. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the ATWS analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.4.2.4

This SR ensures that the LFMG breaker trip portion of the ATWS-RPT initiated from the Reactor Vessel Steam Dome Pressure—High Function will not be inadvertently bypassed for > 29 seconds when THERMAL POWER is > 5% RTP. This involves verification of the time delay and calibration of the APRM Downscale trip channel. Adequate margins for the instrument setpoint methodologies are incorporated into the actual APRM setpoint. If any time delay or APRM Downscale setpoint is nonconservative (i.e., the Reactor Vessel Steam Dome Pressure—High Function is bypassed for > 29 seconds when THERMAL POWER is > 5% RTP), the affected Reactor Vessel Steam Dome Pressure—High Function is considered inoperable. Alternately, if only the APRM Downscale setpoint is nonconservative, the APRM channel can be placed in the conservative condition (e.g., placed in the inop trip condition). If placed in the conservative condition, this SR is met and the associated Reactor Vessel Steam Dome Pressure—High Function is considered OPERABLE.

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the APRM setpoint analysis and is also based upon engineering judgement and the reliability of the time delay components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.5

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.

The Frequency is based upon the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis and engineering judgment.

SR 3.3.4.2.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers, included as part of this Surveillance, overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

REFERENCES

1. USAR, Section 7.6.1.8.
2. 10 CFR 50.36(c)(2)(ii).
3. USAR, Section 15.8.
4. GENE-770-06-1-A, "Bases For Changes To Surveillance Test Intervals And Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that fuel is adequately cooled in the event of a design basis accident or transient.

For most anticipated operational occurrences (AOOs) and Design Basis Accidents (DBAs), a wide range of dependent and independent parameters are monitored.

The ECCS instrumentation actuates low pressure core spray (LPCS), low pressure coolant injection (LPCI), high pressure core spray (HPCS), Automatic Depressurization System (ADS), and the diesel generators (DGs). The equipment involved with each of these systems is described in the Bases for LCO 3.5.1, "ECCS—Operating" or LCO 3.8.1, "AC Sources—Operating."

<u>Low Pressure Core Spray System</u>

The LPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High. Reactor vessel water level is monitored by two redundant differential pressure transmitters and drywell pressure is monitored by two redundant pressure transmitters, each providing input to a trip unit. The outputs of the four trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The LPCS initiation signal is a sealed in signal and must be manually reset. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. Upon receipt of an initiation signal, the LPCS pump is automatically started in approximately 10 seconds if offsite power is available; otherwise the pump is started in approximately 6 seconds after AC power from the DG is available.

The LPCS full flow test line isolation valve, is closed on a LPCS initiation signal to allow full system flow assumed in the accident analysis.

(continued)

BASES

BACKGROUND

Low Pressure Core Spray System (continued)

The LPCS pump discharge flow is monitored by a differential pressure transmitter. When the pump is running and discharge flow is low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The differential pressure between the low pressure side of the LPCS injection valve and the reactor vessel is monitored by a differential pressure transmitter. This ensures that, before the injection valve opens, the reactor pressure has fallen to a value below the maximum design pressure of the LPCS System.

Low Pressure Coolant Injection Subsystems

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with three LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High. Reactor vessel water level is monitored by two redundant differential pressure transmitters per division and drywell pressure is monitored by two redundant pressure transmitters per division, each providing input to a trip unit. The outputs of the four Division 2 LPCI (loops B and C) trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its initiation signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic. The two divisions can also be initiated by use of a manual switch and push button (one per division, with the LPCI A manual switch and push button being common with LPCS), whose two contacts are arranged in a two-out-of-two logic. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

Upon receipt of an initiation signal, the LPCI Pump C is automatically started in approximately 10 seconds if offsite power is available; otherwise the pump is started in approximately 6 seconds after AC power from the DG is available while LPCI pumps A and B are automatically started in approximately 5 seconds if offsite power is available; otherwise the pumps are started in approximately 1 second after AC power from the DG is available. These time delays limit the loading on the normal and standby power sources.

Each LPCI subsystems discharge flow is monitored by a differential pressure transmitter. When a pump is running and discharge flow is low enough that pump overheating may occur, the respective minimum flow return line valve is opened after approximately 8 seconds. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the analyses.

The RHR spray isolation valves (which are also PCIVs) and suppression pool cooling full flow test valves are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and, in the case of the spray isolation valves, to maintain the containment isolated in the event LPCI is not operating.

The RHR A and B heat exchanger sample and RHR B discharge to radwaste valves (Group 4 valves) are closed on either a Reactor Vessel Water Level—Low, Level 3 signal or a Drywell Pressure—High signal to allow full system flow assumed in the accident analysis. (The RHR A discharge to radwaste valves are manual valves; they do not receive an automatic signal.) These valves can also be closed using the remote manual control switches. Reactor vessel water level is monitored by two differential pressure transmitters per division and drywell pressure is monitored by two pressure transmitters per division, each providing input to a trip unit. The outputs of these channels for each Function are arranged into a two-out-of-two trip system for each division. The LPCI A (Division 1) trip systems close the outboard valves while the LPCI B (Division 2) trip systems close the inboard valves. However, since only one of the valves in each line must be closed to preclude flow diversion, and the valves must be capable of closing when

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

the associated LPCI receives an initiation signal, only the valves receiving power and logic from their associated division must be capable of closing. Thus, the LPCI A trip systems must close the outboard RHR A heat exchanger sample valve and LPCI B trip systems must close the inboard RHR B heat exchanger sample valve and the inboard RHR B discharge to radwaste valve.

The differential pressure between the low pressure side of the LPCI injection valves and the reactor vessel is monitored by a differential pressure transmitter. This ensures that, prior to an injection valve opening, the reactor pressure has fallen to a value below the maximum design pressure of the LPCI subsystem.

High Pressure Core Spray System

The HPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High. Reactor vessel water level is monitored by four redundant differential pressure transmitters and drywell pressure is monitored by four redundant pressure transmitters, each providing input to a trip unit. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each variable. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two-logic. The HPCS System initiation signal is a sealed in signal and must be manually reset.

The HPCS pump discharge flow and pressure are monitored by a differential pressure and pressure transmitter, respectively. Each transmitter is connected to a trip unit. When the pump is running (as indicated by the pressure transmitter) and discharge flow is low enough that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow full system flow assumed in the accident analyses.

(continued)

BASES

BACKGROUND

High Pressure Core Spray System (continued)

The HPCS full flow test line isolation valve to the suppression pool (which is also a PCIV) and the full flow test line isolation valves to the CST are closed on a HPCS initiation signal to allow full system flow assumed in the accident analyses and, in the case of the suppression pool isolation valve, maintain the containment isolated in the event HPCS is not operating.

The HPCS System also monitors the HPCS pump suction pressure, which provides an indication of the water level in condensate storage tank B (CST), and the suppression pool water level, since these are the two sources of water for HPCS operation. Reactor grade water in the CST is the normal and preferred source. Upon receipt of a HPCS initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position), unless the suppression pool suction valve is open. If the pump suction pressure (indicating low water level in the CST) falls below a preselected level for a preselected time, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. Two pressure transmitters are used to detect low pump suction pressure and a single time delay relay is used to provide a short delay in the automatic suction swap feature. Either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close (one-out-of-two logic). Once low pump suction pressure is detected, a time delay relay times out, then the automatic suction swap occurs. The suppression pool suction valve also automatically opens and the CST suction valve closes if high water level is detected in the suppression pool. Two differential pressure transmitters are also used to detect high suppression pool water level, with a one-out-of-two logic similar to the pump suction pressure logic. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The HPCS System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip, at which time the HPCS injection valve closes. The HPCS pump will continue to run on minimum flow. The logic is one-out-of-two taken twice to provide high

(continued)

BASES

BACKGROUND

High Pressure Core Spray System (continued)

reliability of the HPCS System. The injection valve automatically reopens if a low low water level signal is subsequently received.

Automatic Depressurization System

ADS may be initiated by either automatic or manual means. Automatic initiation occurs when signals indicating Reactor Vessel Water Level—Low Low Low, Level 1; confirmed Reactor Vessel Water Level—Low, Level 3; and either LPCS or LPCI Pump Discharge Pressure—High are all present, and the ADS Initiation Timer has timed out. There are two differential pressure transmitters for Reactor Vessel Water Level—Low Low Low, Level 1 and one differential pressure transmitter for confirmed Reactor Vessel Water Level—Low, Level 3 in each of the two ADS trip systems. Each of these transmitters connects to a trip unit, which then drives a relay whose contacts form the initiation logic.

Each ADS trip system (trip system A and trip system B) includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The time delay chosen is long enough that the HPCS has time to operate to recover to a level above Level 1, yet not so long that the LPCI and LPCS systems are unable to adequately cool the fuel if the HPCS fails to maintain level. An alarm in the control room is annunciated when either of the timers is running. Resetting the ADS initiation signals resets the ADS Initiation Timers.

The ADS also monitors the discharge pressures of the three LPCI pumps and the LPCS pump. Each ADS trip system includes two discharge pressure permissive transmitters from each of the two low pressure ECCS pumps in the associated Division (i.e., Division 1 ECCS inputs to ADS trip system A and Division 2 ECCS inputs to ADS trip system B). The signals are used as a permissive for ADS actuation, indicating that there is a source of core coolant available once the ADS has depressurized the vessel. Any one of the four low pressure pumps provides sufficient core coolant flow to permit automatic depressurization.

(continued)

BASES

BACKGROUND

Automatic Depressurization System (continued)

The ADS logic in each trip system is arranged in two strings. One string has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3; ADS Initiation Timer; and two low pressure ECCS Discharge Pressure—High contacts (one from each divisional pump). The other string has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1; and two low pressure ECCS Discharge Pressure—High contacts (one from each divisional pump). To initiate an ADS trip system, the following applicable contacts must close in the associated string: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3 (one string only); ADS Initiation Timer (one string only); and one of the two low pressure ECCS Discharge Pressure—High contacts.

Either ADS trip system A or trip system B will cause all the ADS valves to open. Once an ADS trip system is initiated; it is sealed in until manually reset.

Manual initiation for each trip system is accomplished by the use of two manual switch and push buttons, whose four contacts (two per manual switch and push button) are arranged in a four-out-of-four logic (two contacts per ADS logic string). Manual inhibit switches are provided in the control room for ADS; however, their function is not required for ADS OPERABILITY (provided ADS is not inhibited when required to be OPERABLE).

Diesel Generators

The Division 1, 2, and 3 DGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low Low, Level 1 or Drywell Pressure—High for the Division 1 and 2 DGs, and Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High for the Division 3 DG. The DGs are also initiated upon loss of voltage signals. (Refer to Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) Reactor vessel water level is monitored by two redundant differential pressure transmitters and drywell pressure is

(continued)

BASES

BACKGROUND

Diesel Generators (continued)

monitored by two redundant pressure transmitters per DG, each providing input to a trip unit. The outputs of the four divisionalized trip units (two trip units from each of the two variables) are connected to relays whose contacts are connected to a one-out-of-two taken twice logic. The DGs receive their initiation signals from the associated Divisions' ECCS logic (i.e., Division 1 DG receives an initiation signal from Division 1 ECCS (LPCS and LPCI A); Division 2 DG receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C); and Division 3 DG receives an initiation signal from Division 3 ECCS (HPCS)). The DGs can also be started manually from the control room and locally in the associated DG room. The DG initiation signal is a sealed in signal and must be manually reset. The DG initiation logic is reset by resetting the associated ECCS initiation logic. Upon receipt of an ECCS initiation signal, each DG is automatically started, is ready to load in approximately 10 seconds, and will run in standby conditions (rated voltage and speed, with the DG output breaker open). The DGs will only energize their respective emergency buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2, and 3. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS instrumentation satisfies Criterion 3 of Reference 4. Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the ECCS instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Table 3.3.5.1-1, footnote (b), is added to show that certain ECCS instrumentation Functions are also required to be OPERABLE to perform DG initiation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Allowable Values are specified for each ECCS Function specified 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 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 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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

Some Functions (i.e., Functions 1.k, 1.l, 2.j, and 3.g) have both an upper and lower analytic limit that must be evaluated. The Allowable Values and trip setpoints are derived from both an upper and lower analytic limit using the methodology described above. Due to the upper and lower analytic limits, Allowable Values of these Functions appear to incorporate a range. However, the upper and lower Allowable Values are unique, with each Allowable Value associated with one unique analytic limit and trip setpoint.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or DG) initiation to mitigate the consequences

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

of a design basis accident or transient. To ensure reliable ECCS and DG function, a combination of Functions is required to provide primary and secondary initiation signals.

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

Low Pressure Core Spray and Low Pressure Coolant Injection Systems

1.a, 1.b, 2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low Low, Level 1

Low reactor pressure vessel (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. The low pressure ECCS and associated DGs are initiated at Level 1 and certain RHR valves are closed at Level 3 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The Reactor Vessel Water Level—Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel Water Level—Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break (Ref. 2). However, while no credit is taken in these analyses to start the DGs, they are retained for overall redundancy and diversity as required by the NRC in the plant licensing basis. The Reactor Vessel Water Level—Low, Level 3 is implicitly assumed to allow full system flow assumed in References 1 and 3. The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low Low, Level 1 signals are initiated from differential pressure transmitters 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. The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low, Level 3

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 1.b, 2.a, 2.b. Reactor Vessel Water Level—Low, Level 3 and Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

(LCO 3.3.1.1, "RPS Instrumentation,") since the sensors are common to the RPS instrumentation. The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling.

Two channels of Reactor Vessel Water Level—Low, Level 3 Function per associated Division are only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE, to ensure that no single instrumentation failure can preclude ECCS initiation. Two channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function per associated Division are only required to be OPERABLE when the associated ECCS is required to be OPERABLE, to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and the Division 1 DG while the other two channels input to LPCI B, LPCI C, and the Division 2 DG.) Refer to LCO 3.5.1 and LCO 3.5.2, "ECCS—Shutdown," for Applicability Bases for the low pressure ECCS subsystems.

1.c, 1.d, 2.c, 2.d. Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation)

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The low pressure ECCS and associated DGs are initiated upon receipt of the Drywell Pressure—High Function and certain RHR valves are closed upon receipt of the Drywell Pressure—High (Boundary Isolation) Function in order to minimize the possibility of fuel damage. Although, no credit is taken for the Drywell Pressure—High Function to start the low pressure ECCS in any design basis accident or transient analysis (thus Drywell Pressure—High (Boundary Isolation) Function is also not assumed), they are retained for overall redundancy and diversity as required by the NRC in the plant licensing basis. In addition, credit is taken for the Drywell Pressure—High Function to start the associated DGs (Ref. 2). 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 2.c, 2.d. Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation) (continued)

High drywell pressure signals are initiated from pressure transmitters that sense drywell pressure. The Drywell Pressure—High Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment. The Drywell Pressure—High (Boundary Isolation) Allowable Value was chosen to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1) since the sensors are common to the RPS instrumentation.

The Drywell Pressure—High Function is required to be OPERABLE when the associated ECCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the LPCS and LPCI Drywell Pressure—High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS initiation. (Two channels input to LPCS, LPCI A, and the Division 1 DG while the other two channels input to LPCI B, LPCI C, and the Division 2 DG.) The Drywell Pressure—High (Boundary Isolation) is required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the Drywell Pressure—High (Boundary Isolation) Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS initiation. In MODES 4 and 5, the Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation) Functions are not required since there is insufficient energy in the reactor to pressurize the primary containment to the Drywell Pressure—High and Drywell Pressure—High (Boundary Isolation) Functions setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

1.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, 2.h. LPCS and LPCI Pump Start—Time Delay Relays (Normal and Emergency Power)

The purpose of these time delays is to stagger the start of the ECCS pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV emergency buses. The Time Delay Relay (Normal Power) Function is necessary when power is being supplied from offsite power,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, 2.h. LPCS and LPCI Pump Start—Time Delay Relays (Normal and Emergency Power) (continued)

and the Time Delay Relay (Emergency Power) Function is necessary when power is being supplied from the standby power sources (DG). The Pump Start—Time Delay Relays (Normal and Emergency Power) are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analysis assumes that the pumps will initiate when required.

There are four Pump Start—Time Delay Relays (Normal Power) and four Pump Start—Time Delay Relays (Emergency Power), one of each type in each of the low pressure ECCS pump start logic circuits. While each time delay relay is dedicated to a single pump start logic, a single failure of a Pump Start—Time Delay Relay (Normal or Emergency Power) could result in the failure of the two low pressure ECCS pumps, powered from the same emergency bus, to perform their intended function within the assumed ECCS RESPONSE TIMES (e.g., as in the case where both ECCS pumps on one emergency bus start simultaneously due to an inoperable time delay relay). This still leaves two of the four low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Values for the Pump Start—Time Delay Relays (Normal and Emergency Power) are chosen to be short enough so that ECCS operation is not degraded.

Each channel of Pump Start—Time Delay Relay (Normal and Emergency Power) Function is only required to be OPERABLE when the associated low pressure ECCS subsystem is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.i, 1.j, 2.i. LPCS and LPCI Differential Pressure—Low (Injection Permissive)

Low differential pressure across the injection valves signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems maximum design pressure. The Differential

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.i, 1.j, 2.i. LPCS and LPCI Differential Pressure—Low (Injection Permissive) (continued)

Pressure—Low (Injection Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition, the Differential Pressure—Low (Injection Permissive) Function is directly assumed in the analysis of the recirculation line break (Ref. 2). 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.

The Differential Pressure—Low (Injection Permissive) signals are initiated from four differential pressure transmitters that sense the pressure difference across the injection valves of the low pressure ECCS subsystems.

The Allowable Value is low enough to prevent overpressurizing the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

Each channel of Differential Pressure—Low (Injection Permissive) Function (one per valve) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude ECCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.k, 1.l, 2.j. LPCS and LPCI Pump Discharge Flow—Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not sufficiently open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The LPCI and LPCS Pump Discharge Flow—Low (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flows assumed during the transients and accidents analyzed in References 1, 2, and 3 are met. The core cooling

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.k, 1.l, 2.j. LPCS and LPCI Pump Discharge Flow—Low (Bypass) (continued)

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 differential pressure transmitter per ECCS pump is used to detect the associated subsystems flow rate. The logic is arranged such that each transmitter causes its associated minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for approximately 8 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode. The Pump Discharge Flow—Low (Bypass) Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of Pump Discharge Flow—Low (Bypass) Function (one LPCS channel and three 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.m, 2.k. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There is one switch and push button (with two channels per switch and push button) for each of the two Divisions of low pressure ECCS (i.e., Division 1 ECCS, LPCS and LPCI A; Division 2 ECCS, LPCI B and LPCI C).

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.m, 2.k. Manual Initiation (continued)

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Each channel of the Manual Initiation Function (two channels per division) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

High Pressure Core Spray System

3.a. Reactor Vessel Water Level—Low Low, Level 2

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, the HPCS System and associated DG is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level—Low Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCS during the transients analyzed in References 1 and 3. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with HPCS is directly assumed in the analysis of the recirculation line break (Ref. 2). However, no credit is taken in this analysis to start the HPCS DG. 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.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from four differential pressure transmitters 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. The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value is chosen such that for complete loss of feedwater flow, the Reactor Core Isolation Cooling (RCIC) System flow with HPCS

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. Reactor Vessel Water Level—Low Low, Level 2 (continued)

assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level—Low Low Low, Level 1.

Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the RCPB. The HPCS System and associated DG are initiated upon receipt of the Drywell Pressure—High Function in order to minimize the possibility of fuel damage. Although no credit is taken for the Drywell Pressure—High Function to start the HPCS System in any DBA or transient analyses, credit is taken for this Function to start the associated DG; that is, HPCS is assumed to be initiated on Reactor Water Level—Low Low, Level 2 while the associated DG is assumed to be initiated on Drywell Pressure—High. 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.

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

The Drywell Pressure—High Function is required to be OPERABLE when HPCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the HPCS Drywell Pressure—High Function are required to be OPERABLE in MODES 1, 2, and 3, to ensure that no single instrument failure can preclude ECCS initiation. 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 Function setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.c. Reactor Vessel Water Level—High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the HPCS injection valve to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level—High, Level 8 Function is not credited in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk, thus it meets Criterion 4 of Reference 4.

Reactor Vessel Water Level—High, Level 8 signals for HPCS are initiated from four differential pressure transmitters from the wide range water level measurement instrumentation.

The Reactor Vessel Water Level—High, Level 8 Allowable Value is chosen to isolate flow from the HPCS System prior to water overflowing into the MSLs.

Four channels of Reactor Vessel Water Level—High, Level 8 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.d, 3.e. Pump Suction Pressure—Low and Pump Suction Pressure—Timer

Low pump suction pressure, which is an indication of low level in the CST, indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCS and the CST are open and, upon receiving a HPCS initiation signal, water for HPCS injection would be taken from the CST. However, if the pump suction pressure (indicating low water level in the CST) falls below a preselected level for a preselected time, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCS pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. The Functions are

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d, 3.e. Pump Suction Pressure—Low and Pump Suction Pressure—Timer (continued)

implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Pump Suction Pressure—Low signals are initiated from two pressure transmitters. The Pump Suction Pressure—Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST. The pressure at which the transfer occurs also ensures sufficient volume of water is used by the HPCS pump before the transfer occurs and is analytically determined to prevent the effects of vortexing. The Pump Suction Pressure—Timer Function is initiated by a single time delay relay. While the Pump Suction Pressure—Timer Function is provided to prevent spurious suction source automatic swaps, the Allowable Value is low enough such that the automatic suction swap from the CST to the suppression pool will occur before adequate pump suction head is lost.

Two channels of the Pump Suction Pressure—Low Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. In addition, one channel of the Pump Suction Pressure—Timer Function is only required to be OPERABLE when HPCS is required to be OPERABLE. Thus, the Functions are required to be OPERABLE in MODES 1, 2, and 3. In MODES 4 and 5, the Functions are required to be OPERABLE only when HPCS is required to be OPERABLE to fulfill the requirements of LCO 3.5.2, HPCS is aligned to the CST, and the CST water level is not within the limits of SR 3.5.2.2. With CST water level within limits, a sufficient supply of water exists for injection to minimize the consequences of a vessel draindown event. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.f. Suppression Pool Water Level—High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the S/RVs. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.f. Suppression Pool Water Level—High (continued)

HPCS from the CST to the suppression pool to eliminate the possibility of HPCS continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Suppression Pool Water Level—High signals are initiated from two differential pressure transmitters. The Allowable Value for the Suppression Pool Water Level—High Function is chosen to ensure that HPCS will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level—High Function are only required to be OPERABLE in MODES 1, 2, and 3 when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. In MODES 4 and 5, the Function is not required to be OPERABLE since the reactor is depressurized and vessel blowdown, which could cause the design values of the containment to be exceeded, cannot occur. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.g, 3.h. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass)

The minimum flow instruments are provided to protect the HPCS pump from overheating when the pump is operating and the associated injection valve is not sufficiently open. The minimum flow line valve is opened when low flow and high pump discharge pressure are sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump or the discharge pressure is low (indicating the HPCS pump is not operating). The HPCS System Flow Rate—Low (Bypass) and HPCS Pump Discharge Pressure—High (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.g, 3.h. HPCS Pump Discharge Pressure—High (Bypass) and HPCS System Flow Rate—Low (Bypass) (continued)

analyzed in References 1, 2, and 3 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 differential pressure transmitter is used to detect the HPCS System's flow rate. The logic is arranged such that the transmitter causes the minimum flow valve to open, provided the HPCS pump discharge pressure, sensed by another transmitter, is high enough (indicating the pump is operating). The logic will close the minimum flow valve once the closure setpoint is exceeded. (The valve will also close upon HPCS pump discharge pressure decreasing below the setpoint.)

The HPCS System Flow Rate—Low (Bypass) Allowable Values are high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The HPCS Pump Discharge Pressure—High (Bypass) Allowable Value is set high enough to ensure that the valve will not be open when the pump is not operating.

One channel of each Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS Applicability Bases.

3.i. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one switch and push button (with two channels) for the HPCS System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.i. Manual Initiation (continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of the Manual Initiation Function are only required to be OPERABLE when the HPCS System is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for HPCS 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 Function. The Reactor Vessel Water Level—Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accidents analyzed in Reference 2. 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.

Reactor Vessel Water Level—Low Low Low, Level 1 signals are initiated from four differential pressure transmitters 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. The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen high enough to allow time for the low pressure core spray and injection systems to initiate and provide adequate cooling.

Four channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Two channels input to ADS trip system A while the other two channels input to ADS trip system B). Refer to LCO 3.5.1 for ADS Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.b, 5.b. ADS Initiation Timer

The purpose of the ADS Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCS System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCS System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the timer, or to inhibit initiation permanently. The ADS Initiation Timer Function is assumed to be OPERABLE for the accident analyses of Reference 2 that require ECCS initiation and assume failure of the HPCS System.

There are two ADS Initiation Timer relays, one in each of the two ADS trip systems. The Allowable Value for the ADS Initiation Timer is chosen to be short enough so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

Two channels of the ADS Initiation Timer Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.c, 5.c. Reactor Vessel Water Level—Low, Level 3 (Permissive)

The Reactor Vessel Water Level—Low, Level 3 (Permissive) Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level—Low Low Low, Level 1 signals. In order to prevent spurious initiation of the ADS due to spurious Level 1 signals, a Level 3 signal must also be received before ADS initiation commences.

Reactor Vessel Water Level—Low, Level 3 (Permissive) signals are initiated from two differential pressure transmitters 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.c, 5.c. Reactor Vessel Water Level—Low, Level 3 (Permissive) (continued)

vessel. The Allowable Value for Reactor Vessel Water Level—Low, Level 3 (Permissive) is selected at the RPS Level 3 scram Allowable Value for convenience. Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for Bases discussion of this Function.

Two channels of Reactor Vessel Water Level—Low, Level 3 (Permissive) Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d. LPCS and LPCI Pump Discharge Pressure—High

The Pump Discharge Pressure—High signals from the LPCS and LPCI pumps (indicating that the associated pump is running) are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure—High is one of the Functions assumed to be OPERABLE and capable of permitting ADS initiation during the events analyzed in References 2 and 3 with an assumed HPCS failure. For these events, the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This 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.

Pump discharge pressure signals are initiated from eight pressure transmitters, two on the discharge side of each of the four low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure—High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode, and high enough to avoid any condition that results in a discharge pressure permissive when the LPCS and LPCI pumps

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.d, 4.e, 5.d. LPCS and LPCI Pump Discharge Pressure—High (continued)

are aligned for injection and the pumps are not running. The actual operating point of this Function is not assumed in any transient or accident analysis.

Eight channels of LPCS and LPCI Pump Discharge Pressure—High Function (two LPCS and two LPCI A channels input to ADS trip system A, while two LPCI B and two LPCI C channels input to ADS trip system B) are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Refer to LCO 3.5.1 for ADS Applicability Bases.

4.f, 5.e. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the ADS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There are two switch and push buttons (with two channels per switch and push button) for each ADS trip system (total of four).

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the ADS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push buttons. Eight channels of the Manual Initiation Function (four channels per ADS trip system) are only required to be OPERABLE when the ADS is required to be OPERABLE. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS 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

(continued)

BASES

ACTIONS (continued)

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 ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.1-1. The applicable Condition specified in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1, B.2, B.3.1, and B.3.2

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same variable result in redundant automatic initiation capability being lost for the feature(s). Required Action B.1 features would be those that are initiated by Functions 1.a, 1.b, 1.c, 1.d, 2.a, 2.b, 2.c, and 2.d (i.e., low pressure ECCS and associated DGs). The Required Action B.2 features would be the HPCS System and associated DG. For Required Action B.1, redundant automatic initiation capability is lost if: (a) one or more Function 1.a channels and one or more Function 2.a channels are inoperable and untripped, and the associated flow path(s) unisolated; (b) one or more Function 1.b channels and one or more Function 2.b channels are inoperable and untripped; (c) one or more Function 1.c channels and one or more Function 2.c channels are inoperable and untripped; or (d) one or more Function 1.d channels and one or more Function 2.d channels are inoperable and untripped, and the associated flow path(s) unisolated. For Divisions 1 and 2, since each inoperable channel would have Required Action B.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division of low pressure ECCS and DG to be declared inoperable.

(continued)

BASES

ACTIONS

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

However, since channels in both Divisions are inoperable and untripped, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions of ECCS and DG being concurrently declared inoperable. For Required Action B.2, redundant automatic initiation capability (i.e., loss of automatic start capability for Functions 3.a and 3.b) is lost if two Function 3.a or two Function 3.b channels are inoperable and untripped in the same trip system.

In this situation (loss of redundant automatic initiation capability), the 12 hour or 24 hour allowance of Required Action B.3.1 is not appropriate and the feature(s) associated with the inoperable, untripped channels (and associated flow path(s) unisolated, as appropriate) must be declared inoperable within 1 hour. As noted (Note 1 to Required Action B.1 and Required Action B.2), the two Required Actions are only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 12 hours or 24 hours (as allowed by Required Action B.3.1) is allowed during MODES 4 and 5. Notes are also provided (Note 2 to Required Action B.1 and Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed.

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." For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable, untripped channels within the same variable as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCS System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss

(continued)

BASES

ACTIONS

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

of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken. An alternate Required Action is provided (Required Action B.3.2) for Functions 1.a, 1.d, 2.a, and 2.d. For these Functions, in lieu of tripping the channel or entering Condition H (and taking its Required Actions), the affected RHR flow path(s) can be isolated. Isolating the affected flow path(s) accomplishes the safety function of the inoperable channel and does not render the associated LPCI subsystem inoperable. Therefore, this action is acceptable. The allowed Completion Time for isolating the affected flow path(s) is the same as the Completion Time allowed for these Functions in Required Action B.3.1.

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same variable result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.e, 1.f, 1.g, 1.h, 1.i, 1.j, 2.e, 2.f, 2.g, 2.h,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

and 2.i (i.e., low pressure ECCS). For Functions 1.e, 1.f, 2.e, and 2.f, redundant automatic initiation capability is lost if the Function 1.e or 1.f channel concurrent with Function 2.e or 2.f channel are inoperable. For Functions 1.g, 1.h, 2.g, and 2.h, redundant automatic initiation capability is lost if the Function 1.g or 1.h channel concurrent with Function 2.g or 2.h channel are inoperable. For Functions 1.i, 1.j, and 2.i, redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.i, 1.j, and 2.i are inoperable. In addition, a Pump Start —Time Delay Relay may be inoperable in such a fashion that the associated offsite circuit or DG is affected (e.g., as in the case where two loads start outside the proper load block interval). If this is the case, the associated ACTIONS of LCO 3.8.1 or LCO 3.8.2, as appropriate, need to be taken. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division to be declared inoperable. However, since channels in both Divisions are inoperable, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions being concurrently declared inoperable. For Functions 1.e, 1.f, 1.g, 1.h, 2.e, 2.f, 2.g, and 2.h, the affected portion of the Divisions are LPCS, LPCI A, LPCI B, and LPCI C. For Functions 1.i, 1.j, and 2.i, the affected portions of the Division are only those low pressure ECCS pumps directly affected by the inoperable channel (i.e., whose injection valve will not actuate properly due to an inoperable channel).

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour. As noted (Note 1), the Required Action is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of automatic initiation capability for 24 hours (as allowed by Required Action C.2) is allowed during MODES 4 and 5.

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BASES

ACTIONS

C.1 and C.2 (continued)

Note 2 states that Required Action C.1 is only applicable for Functions 1.e, 1.f, 1.g, 1.h, 1.i, 1.j, 2.e, 2.f, 2.g, 2.h, and 2.i. The Required Action is not applicable to Functions 1.m, 2.k, and 3.i (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed. Required Action C.1 is also not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of the Function was considered during the development of Reference 5 and considered acceptable for the 24 hours allowed by Required Action C.2.

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." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both Divisions (i.e., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable channels within the same variable as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or would not necessarily result in a safe state for the channel in all events.

(continued)

BASES

ACTIONS (continued)

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

Required Action D.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 automatic component initiation capability for the HPCS System. Automatic HPCS initiation capability is lost if two Function 3.d channels or two Function 3.f channels are inoperable and untripped or if the one Function 3.e channel is inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCS System must be declared inoperable within 1 hour after discovery of loss of HPCS initiation capability. As noted, the Required Action is only applicable if the HPCS pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

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." For Required Action D.1, the Completion Time only begins upon discovery that the HPCS System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or Required Action D.2.2 is performed, measures should be taken to ensure that the HPCS System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1

(continued)

BASES

ACTIONS

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

and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCS suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the LPCS and LPCI Pump Discharge Flow—Low (Bypass) Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.k, 1.l, and 2.j (i.e., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.k, 1.l, and 2.j are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the feature(s) associated with each inoperable channel must be declared inoperable within 1 hour after discovery of loss of initiation capability for feature(s) in both Divisions. As noted (Note 1 to Required Action E.1), Required Action E.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the low pressure ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 7 days (as allowed by Required Action E.2) is allowed during MODES 4 and 5. A Note is also provided (Note 2 to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCS Functions 3.g and 3.h since the loss of one channel results

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 5 and considered acceptable for the 7 days allowed by Required Action E.2.

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." For Required Action E.1, the Completion Time only begins upon discovery that three channels of the variable (Pump Discharge Flow—Low) cannot be automatically initiated due to inoperable channels. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation such that the valve would not automatically close, a portion of the pump flow could be diverted from the reactor injection path, causing insufficient core cooling. These consequences can be averted by the operator's manual control of the valve, which would be adequate to maintain ECCS pump protection and required flow. Furthermore, other ECCS pumps would be sufficient to complete the assumed safety function if no additional single failure were to occur. The 7 day Completion Time of Required Action E.2 to restore the inoperable channel to OPERABLE status is reasonable based on the remaining capability of the associated ECCS subsystems, the redundancy available in the ECCS design, and the low probability of a DBA occurring during the allowed out of service time. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one or more Function 4.a channels and one or more Function 5.a channels are inoperable and untripped, or (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action F.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems.

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." For Required Action F.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable, (b) one or more Function 4.d channels and one or more Function 5.d channels are inoperable, or (c) one or more Function 4.e channels and one or more Function 5.d channels are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems. The Note to Required Action G.1 states that Required Action G.1 is only applicable for Functions 4.b, 4.d, 4.e, 5.b, and 5.d. Required Action G.1 is not applicable to Functions 4.f and 5.e (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 96 hours or 8 days (as allowed by Required Action G.2) is allowed.

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." For Required Action G.1, the Completion Time only begins

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions, as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE (Required Action G.2). If either HPCS or RCIC is inoperable, the time is reduced to 96 hours. If the status of HCPS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

H.1

With any Required Action and associated Completion Time not met, the associated feature(s) may be incapable of performing the intended function and the supported feature(s) associated with the inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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 as follows: (a) for Functions 3.e, 3.g, 3.h, and 3.i; and (b) for Functions other than 3.e, 3.g, 3.h, and 3.i provided the associated Function or redundant Function maintains ECCS 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 reliability analyses (Refs. 5 and 6) 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 ECCS will initiate when necessary.

SR 3.3.5.1.1

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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. 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 and 6.

SR 3.3.5.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be not within its required Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

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

SR 3.3.5.1.4 and SR 3.3.5.1.5

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.

The Frequency of SR 3.3.5.1.4 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 3.3.5.1.5 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.6

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

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Section 5.2.
2. USAR, Section 6.3.
3. USAR, Chapter 15.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.
6. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level such that initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

The RCIC System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level—Low Low, Level 2. The variable is monitored by four differential pressure transmitters that are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic arrangement. The logic can also be initiated by use of a manual switch and push button, whose two contacts are arranged in a two-out-of-two logic. Once initiated, the RCIC logic seals in and can be reset by the operator only when the reactor vessel water level signals have cleared.

The RCIC test line isolation valve is closed on a RCIC initiation signal to allow full system flow to the reactor vessel.

The RCIC System also monitors the RCIC pump suction pressure, which provides an indication of the water level in the condensate storage tank A (CST), since this is the initial source of water for RCIC operation. Reactor grade water in the CST is the normal source. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction valve from the suppression pool is open. If the pump suction pressure (water level in the CST) falls below a preselected pressure for a preselected time, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. Two pressure transmitters are used to

(continued)

BASES

BACKGROUND (continued)

detect low pump suction pressure (water level in the CST) and a single time delay relay is used to provide a short delay in the automatic suction swap feature. Either transmitter along with its associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close (one-out-of-two logic). Once low pump suction pressure is detected, a time delay relay times out, then the automatic suction swap occurs. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (one-out-of-two taken twice logic), at which time the RCIC steam supply valve closes (the injection valve also closes due to the closure of the steam supply valve). The RCIC System restarts if vessel level again drops to the low level initiation point (Level 2).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The function of the RCIC System, to provide makeup coolant to the reactor, is to respond to transient events. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analysis for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the RCIC System, and therefore its instrumentation, meets Criterion 4 of Reference 1. Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RCIC System instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.2-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RCIC System instrumentation Function specified 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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., reactor vessel water level), 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 analysis. The Allowable Values are derived from the analytic limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The individual Functions are required to be OPERABLE in MODE 1, and in MODES 2 and 3 with reactor steam dome pressure > 150 psig, since this is when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for Applicability Bases for the RCIC System.

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

1. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level—Low Low, Level 2 (continued)

fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from four differential pressure transmitters 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.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with high pressure core spray assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Level 1.

Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2. Reactor Vessel Water Level—High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam supply valve to prevent overflow into the main steam lines (MSLs). (The injection valve also closes due to the closure of the steam supply valve; but this is not required for OPERABILITY of the Level 8 instrumentation.)

Reactor Vessel Water Level—High, Level 8 signals for RCIC are initiated from four differential pressure transmitters from the wide range water level measurement instrumentation, which 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Reactor Vessel Water Level—High, Level 8 (continued)

The Reactor Vessel Water Level—High, Level 8 Allowable Value is high enough to preclude isolating the injection valve of the RCIC during normal operation, yet low enough to trip the RCIC System prior to water overflowing into the MSLs.

Four channels of Reactor Vessel Water Level—High, Level 8 Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3, 4. Pump Suction Pressure—Low and Pump Suction Pressure—Timer

Low pump suction pressure, which is an indication of low level in the CST, indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valve between the RCIC pump and the CST is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CST. However, if the pump suction pressure (water level in the CST) falls below a preselected pressure for a preselected time, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. This ensures that an adequate supply at makeup water is available to the RCIC pump. The pressure at which the transfer occurs ensures sufficient volume of water is used by the RCIC pump before the transfer occurs and is analytically determined to prevent the effects of vortexing. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes.

Two pressure transmitters are used to detect low pump suction pressure (water level in the CST). The Pump Suction Pressure—Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CST. The Pump Suction Pressure—Timer Function is initiated by a single time delay relay. While the Pump Suction Pressure—Timer Function is provided to prevent spurious suction source automatic swaps, the Allowable Value

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3, 4. Pump Suction Pressure—Low and Pump Suction Pressure—Timer (continued)

is low enough such that the automatic suction swap from the CST to the suppression pool will occur before adequate pump suction head is lost.

Two channels of Pump Suction Pressure—Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. In addition, one channel of the Pump Suction Pressure—Timer is required to be OPERABLE when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for RCIC Applicability Bases.

5. Manual Initiation

The Manual Initiation switch and push button channels introduce a signal into the RCIC System initiation logic that is redundant to the automatic protective instrumentation and provides manual initiation capability. There is one switch and push button (with two channels) for the RCIC System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the RCIC function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the switch and push button. Two channels of Manual Initiation are required to be OPERABLE when RCIC is required to be OPERABLE. Refer to LCO 3.5.3 for RCIC Applicability Bases.

ACTIONS

A Note has been provided (Note 1) to modify the ACTIONS related to RCIC 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.

(continued)

BASES

ACTIONS (continued)

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 RCIC 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 RCIC System instrumentation channel.

A second Note has been added (Note 2) that allows the Function 2 channels to be inoperable solely for performance of SR 3.5.3.4 without requiring entry into the associated Conditions and Required Actions. The Reactor Vessel Water Level—High, Level 8 Function uses the wide range water level instruments, which are calibrated under hot conditions. However, SR 3.5.3.4 (the RCIC System flow test performed at low reactor pressure) is performed under conditions that result in the wide range water level instruments reading higher than actual reactor vessel water level (which is controlled using the narrow range water level instruments). The readings can be such that the level 8 trip is received. Therefore, this Note allows bypassing all the channels of the Reactor Vessel Water Level—High, Level 8 Function to perform SR 3.5.3.4. This is acceptable since the duration of the Surveillance test is short and the RCIC System is being controlled by an operator who can secure the RCIC System if an actual high water level condition (as indicated by the narrow range instruments) is detected.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.2-1 in the accompanying LCO. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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 automatic initiation capability for the RCIC System (i.e., loss of automatic low water level start capability for Function 1 and loss of automatic high water level trip capability for Function 2). In this case, automatic initiation capability is lost if two channels of a Function, in the same trip system, are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

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." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable untripped Reactor Vessel Water Level—Low Low, Level 2 channels in the same trip system or two inoperable, untripped Reactor Vessel Water Level—High, Level 8 channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 2) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1), limiting the allowable out of service time if a loss of manual RCIC initiation capability exists, is not required. This is allowed since this Function is not assumed in any accident or transient analysis, thus a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in the safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple inoperable, untripped channels within the same Function result in automatic initiation capability being lost for the RCIC System. In this case, automatic initiation capability is lost if two Function 3 channels are inoperable and untripped or if the one Function 4 channel is inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

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." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS

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

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 2) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.2-1.

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 as follows: (a) for up to 6 hours for Functions 4 and 5; and (b) for up to 6 hours for Functions 1, 2, and 3 provided the associated Function maintains RCIC 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

taken. This Note is based on the reliability analysis (Ref. 2) 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 RCIC will initiate when necessary.

SR 3.3.5.2.1

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 that 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. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.5.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be re-adjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.5.2.4

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter with 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 a 24 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.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.3.5.2.5 (continued) Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.
REFERENCES	1. 10 CFR 50.36(c)(2)(ii). 2. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

The primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) ambient and differential temperatures and time delay relays, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum loss, (f) main steam line pressure, (g) reactor core isolation cooling (RCIC) and RCIC/residual heat removal (RHR) steam line flow and time delay relays, (h) Standby Gas Treatment (SGT) System exhaust radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential flow and time delay relays, (l) reactor vessel pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. The only exception is the SGT System exhaust radiation sensor. In addition, manual isolation of the logics is provided.

The primary containment isolation instrumentation has inputs to the trip logic from the isolation Functions listed below.

(continued)

BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two trip systems to isolate all MSL drain valves. One two-out-of-two trip system is associated with the inboard valve and the other two-out-of-two trip system is associated with the outboard valves.

The exceptions to this arrangement are the Main Steam Line Flow—High, Main Steam Line Tunnel Lead Enclosure Temperature—High, and the Manual Initiation Functions. The Main Steam Line Flow—High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of four trip strings. Two trip strings make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two logic. Therefore, this is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two trip systems (effectively, two one-out-of-four taken twice logic), with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Main Steam Line Tunnel Lead Enclosure Temperature—High Function uses 12 temperature channels, three for each trip string. One sensor in each trip string is measuring the temperature in one of the three areas of the lead enclosure. Two trip strings make up each trip system, and both trip systems must trip to cause a MSL isolation. One sensor is required to trip the trip string. The trip strings within a trip system are arranged in a one-out-of-two logic. Therefore, this is effectively a one-out-of-two taken twice logic arrangement for each enclosure area to initiate isolation of the MSIVs. The 12 temperature channels are connected into two two-out-of-two trip systems for each enclosure area, with one trip system isolating the inboard MSL drain valve and the other trip system isolating the outboard MSL drain valves. The Manual Initiation Function uses eight channels, two per switch and push button. The four channels from two

(continued)

BASES

BACKGROUND

1. Main Steam Line Isolation (continued)

switch and push buttons input into one trip system and the four channels from the other two switch and push buttons input into the other trip system. To close all MSIVs, both trip systems must actuate, similar to all the other Functions described above. However, the logic of each trip system is arranged such that both channels from one of the associated switch and push buttons are required to actuate the trip system (i.e., the switch and push button must be both armed and depressed for the trip system to actuate). To close the MSL drain valves, all channels in both trip systems must actuate (i.e., both channels from each of the two associated switch and push buttons are required to actuate the inboard valve trip system and both channels from each of the two associated switch and push buttons are required to actuate the outboard valve trip system).

MSL Isolation Functions isolate the Group 1 valves.

2. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from four channels. The outputs from these channels are arranged into two two-out-of-two trip systems. The two exceptions to this logic arrangement are the SGT System Exhaust Radiation—High and the Manual Initiation Functions. The SGT System Exhaust Radiation—High Function uses two channels, with one channel in each trip system arranged in a one-out-of-one logic. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. In general, one trip system initiates isolation of all inboard PCIVs, while the other trip system initiates isolation of all outboard PCIVs. Each trip system closes one of the two valves on each penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement, which have been previously approved by the NRC as part of the issuance of the Operating License, are described in USAR Table 6.2-56 (Ref. 1). In addition, the withdrawal of the traversing in-core probes using the drive mechanisms is part of the Group 3 isolation valve function.

(continued)

BASES

BACKGROUND

2. Primary Containment Isolation (continued)

Reactor Vessel Water Level—Low, Low, Level 2 Function isolates the Group 2, 3, 8, and 9 valves. Drywell Pressure—High isolates the Group 3, 8, and 9 valves. SGT System Exhaust Radiation—High Function isolates the Group 9 valves.

3. Reactor Core Isolation Cooling System Isolation

Most Functions receive input from two channels, with each channel in one trip system using one-out-of-one logic. Functions 3.g, 3.h, and 3.i (RHR Equipment Room Area Temperature—High, Reactor Building Pipe Chase Area Temperature—High, and Reactor Building General Area Temperature—High Functions) have one channel in each trip system in each room/area for a total of four, eight, and ten channels per Function, respectively; but the logic is the same (one-out-of-one per room/area). One of the two trip systems is connected to the inboard valves and the other trip system is connected to the outboard valve on the RCIC penetration so that operation of either trip system isolates the penetration. Two exceptions to this arrangement are the RCIC Steam Supply Pressure—Low and the RCIC Turbine Exhaust Diaphragm Pressure—High Functions. These Functions receive input from four steam supply pressure channels and four turbine exhaust diaphragm pressure channels, respectively. The outputs from these channels are connected into two two-out-of-two trip systems, each trip system isolating the inboard or outboard RCIC valves. In addition, the RCIC System Isolation Manual Initiation Function has only one channel, which isolates the outboard RCIC valve only (provided an automatic initiation signal is present).

RCIC System Isolation Functions isolate the Group 10 valves.

4. Reactor Water Cleanup System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Functions 4.d and 4.e (Pump Room Area Temperature—High and Reactor Building Pipe Chase Area Temperature—High) have one channel in each trip system in each room/area for a total of four and eight channels per Function, respectively, but the logic is the same (one-out-of-one per room/area). Each of

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4. Reactor Water Cleanup System Isolation (continued)

the two trip systems is connected to one of the two valves on the RWCU penetration so that operation of either trip system isolates the penetration. The exceptions to this arrangement are the Reactor Vessel Water Level—Low Low, Level 2 and the Manual Initiation Functions. The Reactor Vessel Water Level—Low Low, Level 2 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems, each trip system isolating one of the two RWCU valves. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. Each trip system isolates one of the two RWCU valves.

RWCU System Isolation Functions isolate the Group 6 and 7 valves.

5. RHR Shutdown Cooling (SDC) System Isolation

The RHR Shutdown Cooling System Isolation receives input signals from six Functions. The Reactor Vessel Water Level—Low and Reactor Vessel Pressure—High Functions each have four channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. The reactor vessel pressure is arranged into two one-out-of-two trip systems. RHR Equipment Room Area Temperature—High, Reactor Building Pipe Chase Area Temperature—High, and Reactor Building General Area Temperature—High Functions each have one channel in each trip system in each area (one-out-of-one logic for each area) for a total of four, eight, and ten channels per Function, respectively. The Manual Initiation Function uses eight channels, two per switch and push button. Four channels from two switch and push buttons input into one trip system and four channels from the other two switch and push buttons input into the other trip system, with the channels connected in a four-out-of-four logic. Each of the two trip systems is connected to one of the two valves on the shutdown cooling suction line penetration so that

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BACKGROUND

5. RHR Shutdown Cooling (SDC) System Isolation (continued)

operation of either trip system isolates the penetration. In addition, each of the two trip systems is connected to the shutdown cooling return line valves of one RHR SDC subsystem, and one trip system is connected to the RHR reactor head spray outboard isolation valve.

The RHR Shutdown Cooling System Isolation Functions isolate the Group 5 valves.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 2 and 3 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases, for more detail.

Primary containment isolation instrumentation satisfies Criterion 3 of Reference 4. Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each Primary Containment Isolation Function specified 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 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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

Certain Emergency Core Cooling Systems (ECCS) valves (e.g., RHR suppression pool spray isolation valves) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS. Some instrumentation and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "ECCS Instrumentation," and are not included in this LCO.

In general, the individual Functions are required to be OPERABLE in MODES 1, 2, and 3 consistent with the Applicability for LCO 3.6.1.1, "Primary Containment." Functions that have different Applicabilities are discussed below in the individual Functions discussion.

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

<u>1. Main Steam Line Isolation</u>

<u>1.a. Reactor Vessel Water Level—Low Low Low, Level 1</u>

Low reactor pressure vessel (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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Low, Level 1 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Low, Level 1 Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 2). The isolation of the MSL on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four differential pressure transmitters 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. Four channels of Reactor Vessel Water Level—Low Low Low, Level 1 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Level 1 Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits.

This Function isolates the Group 1 valves.

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hour if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 5). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hour) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Main Steam Line Pressure—Low (continued)

Function closes the MSIVs prior to pressure decreasing below 766 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

The MSL low pressure signals are initiated from four pressure transmitters that are connected to the MSL header. The transmitters are arranged such that, even though physically separated from each other, each transmitter is able to detect low MSL pressure. Four channels of Main Steam Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 4).

This Function isolates the Group 1 valves.

1.c. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow—High Function is directly assumed in the analysis of the main steam line break (MSLB) accident (Ref. 6). The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

The MSL flow signals are initiated from 16 differential pressure transmitters that are connected to the four MSLs (the differential pressure transmitters sense differential pressure across a flow venturi). The transmitters are arranged such that, even though physically separated from

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow—High (continued)

each other, all four connected to one steam line would be able to detect the high flow. Four channels of Main Steam Line Flow—High Function for each MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

This Function isolates the Group 1 valves.

1.d. Condenser Vacuum—Low

The Condenser Vacuum—Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum (Ref. 7). Since the integrity of the condenser is an assumption in offsite dose calculations (Ref. 8), the Condenser Vacuum—Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum—Low Function are available and are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3, when all turbine stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

This Function isolates the Group 1 valves.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.e, 1.f. Main Steam Line Tunnel Temperature and Differential Temperature—High

Temperature and Differential Temperature—High is provided to detect a leak in a main steam line, and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSLBs.

Temperature—High signals are initiated from thermocouples located in the area being monitored. Four channels of Main Steam Tunnel Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Eight thermocouples provide input to the Main Steam Tunnel Differential Temperature—High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system. Four channels of Main Steam Line Tunnel Differential Temperature—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The temperature and differential temperature monitoring Allowable Values are chosen to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 1 valves.

1.g. Main Steam Line Tunnel Lead Enclosure Temperature—High

Main Steam Line Tunnel Lead Enclosure Temperature—High is provided to detect a leak in a main steam line in the main steam line tunnel lead enclosure and also provides diversity to the high flow instrumentation. This enclosure is divided in three areas (west, center, and east). The isolation

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.g. Main Steam Line Tunnel Lead Enclosure Temperature—High (continued)

occurs when a very small leak has occurred in any one of the three areas of the enclosure. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSL breaks.

Main Steam Line Tunnel Lead Enclosure Temperature—High signals are initiated from thermocouples located in the area being monitored. Twelve channels of Main Steam Line Tunnel Lead Enclosure Temperature—High Function are available and are required to be OPERABLE (four in each of the three areas) to ensure that no single instrument failure can preclude the isolation function.

The Main Steam Line Tunnel Lead Enclosure Temperature—High Allowable Value is chosen to detect a leak equivalent to 25 gpm. In addition, as ambient temperature in the main steam line tunnel lead enclosure increases, the Allowable Value is allowed to be increased as described in footnote (b) to Table 3.3.6.1-1. This is permitted provided the main steam line tunnel lead enclosure is visually inspected to ensure the ambient temperature increase is not due to a steam leak.

This Function isolates the Group 1 valves.

1.h. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the MSL isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. Eight channels of Manual

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b Manual Initiation (continued)

Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the MSL Isolation automatic Functions are required to be OPERABLE.

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

This Function isolates the Group 1 valves.

2. Primary Containment Isolation

2.a. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 2 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure transmitters 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. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 2, 3, 8, and 9 valves.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.b. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the drywell. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure—High Function associated with isolation of the primary containment is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the RPS Drywell Pressure—High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 3, 8, and 9 valves.

2.c. Standby Gas Treatment (SGT) System Exhaust Radiation—High

High ventilation exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Exhaust Radiation—High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products.

The Exhaust Radiation—High signals are initiated from a radiation detector that is located on the ventilation exhaust piping of the SGT System. The signal from the detector is input to an individual monitor whose trip output, after a preselected time delay, is assigned to both isolation channels. Two channels of SGT Exhaust—High Function are available and are required to be OPERABLE to ensure that no single instrument failure, other than the sensor/trip output, can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Standby Gas Treatment (SGT) System Exhaust Radiation—High (continued)

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding and to ensure offsite doses remain below 10 CFR 20 and 10 CFR 100 limits.

This Function isolates the Group 9 valves.

2.d. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the primary containment isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, with two switch and push buttons per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES in which the Primary Containment Isolation automatic Functions are required to be OPERABLE.

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

This Function isolates the Group 2, 3, 8, and 9 valves.

3. Reactor Core Isolation Cooling System Isolation

3.a. RCIC Steam Line Flow—High

RCIC Steam Line Flow—High Function is provided to detect a break of the RCIC steam lines and initiates closure of the steam line isolation valves. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and core uncovery can occur. Therefore, the isolation is initiated on high flow to prevent or minimize

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. RCIC Steam Line Flow—High (continued)

core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any USAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow—High signals are initiated from two differential pressure transmitters that are connected to the system steam lines. Two channels of RCIC Steam Line Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

This Function isolates the Group 10 valves.

3.b. RCIC Steam Line Flow—Timer

The RCIC Steam Line Flow—Timer is provided to prevent false isolations on RCIC Steam Line Flow—High during system startup transients and therefore improves system reliability. This Function is not assumed in any USAR transient or accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow—Timer Function delays the RCIC Steam Line Flow—High signals by use of time delay relays. When an RCIC Steam Line Flow—High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels of RCIC Steam Line Flow—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. RCIC Steam Line Flow—Timer (continued)

The Allowable Value was chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

This Function isolates the Group 10 valves.

3.c. RCIC Steam Supply Pressure—Low

Low RCIC steam supply pressure indicates that the pressure of the steam in the RCIC turbine may be too low to continue operation of the RCIC turbine. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the USAR. However, it also provides a diverse signal to indicate a possible system break. These instruments are included in the Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 4.

The RCIC Steam Supply Pressure—Low signals are initiated from four pressure transmitters that are connected to the RCIC steam line. Four channels of RCIC Steam Supply Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is selected to be high enough to prevent damage to the RCIC turbine.

This Function isolates the Group 10 valves.

3.d. RCIC Turbine Exhaust Diaphragm Pressure—High

High turbine exhaust diaphragm pressure indicates that the pressure may be too high to continue operation of the RCIC turbine. That is, one of two exhaust diaphragms has ruptured and pressure is reaching turbine casing pressure limits. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the USAR. These instruments are included in the TS because of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d. RCIC Turbine Exhaust Diaphragm Pressure—High (continued)

the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 4.

The RCIC Turbine Exhaust Diaphragm Pressure—High signals are initiated from four pressure transmitters that are connected to the area between the rupture diaphragms on the RCIC turbine exhaust line. Four channels of RCIC Turbine Exhaust Diaphragm Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is selected to be low enough to prevent damage to the RCIC turbine.

This Function isolates the Group 10 valves.

3.e, 3.f, 3.g, 3.h, 3.i. Area Temperature—High

Area Temperatures are provided to detect a leak from the RCIC steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area Temperature—High signals are initiated from thermocouples that are located in the area that is being monitored. Two instruments for each Function monitor each area. Two channels for each area monitored by the Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the RCIC equipment room area, two channels for the RCIC steam line tunnel area, and four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area).

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e, 3.f, 3.g, 3.h, 3.i. Area Temperature—High (continued)

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 10 valves.

3.j. Area Temperature—Timer

The RCIC Area Temperature—Timer is provided to ensure RCIC is not isolated if power is lost to the Area Temperature—High Functions control circuits (the control circuits are powered from the RPS logic buses). This Function is not assumed in any USAR transient or accident analysis since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

The Area Temperature—Timer Function delays all Area Temperature—High signals associated with RCIC isolation by use of time delay relays. When an Area Temperature—High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels for Area Temperature—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be long enough to ensure a loss of power to the Area Temperature—High control circuits does not result in an isolation, but not so long as to impact offsite dose calculations.

This Function isolates the Group 10 valves.

3.k. RCIC/RHR Steam Flow—High

RCIC/RHR high steam line flow is provided to detect a break of the common steam line of RCIC and RHR (steam condensing mode) and initiates closure of the RCIC isolation valves. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. Therefore, the isolation is initiated at high flow to prevent or minimize core damage. The isolation action along with the scram function of RPS ensures that the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.k. RCIC/RHR Steam Flow—High (continued)

fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any USAR accident or transient analysis since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC/RHR steam line break from becoming bounding.

The RCIC/RHR steam line flow signals are initiated from two differential pressure transmitters that are connected to the steam line. Two channels with one channel in each trip system are available and required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Allowable Value is chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB as the bounding event.

This Function actuates the Group 10 valves.

3.l. RCIC/RHR Steam Flow—Timer

The RCIC/RHR Steam Flow—Timer is provided to prevent false isolations on RCIC/RHR Steam Flow—High during system startup transients and therefore improves system reliability. This Function is not assumed in any USAR transient or accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC/RHR Steam Flow—Timer Function delays the RCIC/RHR Steam Flow—High signals by use of time delay relays. When a RCIC/RHR Steam Flow—High signal is generated, the time delay relays delay the tripping of the associated RCIC isolation trip system for a short time. Two channels of RCIC/RHR Steam Flow—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

This Function isolates the Group 10 valves.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.m. Manual Initiation

The Manual Initiation push button channel introduces a signal into the RCIC System isolation logic that is redundant to the automatic protective instrumentation and provides manual isolation capability (when a system initiation signal is present). There is no specific USAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There is one push button for RCIC. One channel of Manual Initiation Function is available and is required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RCIC System Isolation automatic Functions are required to be OPERABLE. As noted (footnote (c) to Table 3.3.6.1-1), this Function is only required to close the outboard Group 10 RCIC isolation valve since the signal only provides input into one of the two trip systems.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button.

This Function isolates the outboard Group 10 valve.

4. Reactor Water Cleanup System Isolation

4.a. Differential Flow—High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow is sensed to prevent exceeding offsite doses. A time delay (Function 4.b, described below) is provided to prevent spurious trips during most RWCU operational transients. This Function is not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLE

4.a. Differential Flow—High (continued)

The high differential flow signals are initiated from two differential pressure transmitters that are connected to the inlet (from the reactor vessel) and four differential pressure transmitters from the outlets (to condenser and feedwater) of the RWCU System. The outputs of the transmitters are compared (in two different summers) and the outputs are sent to two flow switches. If the difference between the inlet and outlet flow is too large, each flow switch generates an isolation signal. Two channels of Differential Flow—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow—High Allowable Value ensures that the break of the RWCU piping is detected.

This Function isolates the Group 6 and 7 valves.

4.b. Differential Flow—Timer

The Differential Flow—Timer is provided to avoid RWCU System isolations due to operational transients (such as pump starts and mode changes). During these transients the inlet and return flows become unbalanced for short time periods and Differential Flow—High will be sensed without an RWCU System break being present. Credit for this Function is not assumed in the USAR accident or transient analysis; since bounding analyses are performed for large breaks such as MSLBs.

The Differential Flow—Timer Function delays the Differential Flow—High signals by use of time delay relays. When a Differential Flow—High signal is generated, the time delay relays delay the tripping of the associated RWCU isolation trip system for a short time. Two channels for Differential Flow—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Differential Flow—Timer Allowable Value is selected to ensure that the MSLB outside containment remains the limiting break for USAR analysis for offsite dose calculations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.b. Differential Flow—Timer (continued)

This Function isolates the Group 6 and 7 valves.

4.c, 4.d, 4.e. Area Temperature—High

Area Temperature—High is provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred and is diverse to the high differential flow instrumentation for the hot portions of the RWCU System. If the small leak continues without isolation, offsite dose limits may be reached. Credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature—High signals are initiated from thermocouples that are located in the room that is being monitored. There are 14 thermocouples that provide input to the Area Temperature—High Function (two per area). Fourteen channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the heat exchanger room, four channels for the pump rooms (two per room), and eight for the reactor building pipe chase areas (two per area).

The Area Temperature—High Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 6 and 7 valves.

4.f. Reactor Vessel Water Level—Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level—Low Low, Level 2 Function associated with RWCU isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.f. Reactor Vessel Water Level—Low Low, Level 2 (continued)

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure transmitters 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. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 6 and 7 valves.

4.g. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been manually initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 9). SLC System initiation signals are initiated from the two SLC pump start signals.

Two channels (one from each pump) of SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7, "SLC System"). Compliance with Reference 10 (NMP2 requires both SLC pumps to be manually started to inject boron) ensures that no single instrument failure can preclude the isolation function.

There is no Allowable Value associated with this Function since the channels are mechanically actuated based solely on the position of the SLC System initiation switches.

This Function isolates the Group 6 and 7 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.h. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RWCU System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, two switch and push buttons per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RWCU System Isolation automatic Functions are required to be OPERABLE.

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

This Function isolates the Group 6 and 7 valves.

5. RHR Shutdown Cooling System Isolation

5.a, 5.d, 5.e. Area Temperature—High

Area Temperature—High is provided to detect a leak from the RHR SDC System piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature—High signals are initiated from thermocouples that are located in the area that is being monitored. Two instruments for each Function monitor each area/room. Twenty-two channels for Area Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a, 5.d, 5.e. Area Temperature—High (continued)

isolation function. There are four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area).

The Area Temperature—High Functions are only required to be OPERABLE in MODE 3. In MODES 1 and 2, the Reactor Vessel Pressure—High Function and other administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 5 valves.

5.b. Reactor Vessel Water Level—Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level—Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs. The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

Reactor Vessel Water Level—Low, Level 3 signals are initiated from differential pressure transmitters 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. Four channels (two channels per trip system) of the Reactor Vessel Water Level—Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d)

(continued)

BASES

APPLICABLE SAFETY ANANYSES, LCO, and APPLICABILITY

5.b. Reactor Vessel Water Level—Low, Level 3 (continued)

to Table 3.3.6.1-1), only one trip system is required to be OPERABLE in MODES 4 and 5 provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level—Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering reactor vessel level to the top of the fuel. In MODES 1 and 2, the Reactor Vessel Pressure—High Function and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Reactor Vessel Water Level—Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low, Level 3 Allowable Value (LCO 3.3.1.1) since the capability to cool the fuel may be threatened.

This Function isolates the Group 5 valves.

5.c. Reactor Vessel Pressure—High

The Shutdown Cooling System Reactor Vessel Pressure—High Function is provided to isolate the shutdown cooling portion of the RHR System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario and credit for the interlock is not assumed in the accident or transient analysis in the USAR.

The Reactor Vessel Pressure—High signals are initiated from four pressure transmitters. Four channels of Reactor Vessel Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 5 valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5.f. Manual Initiation

The Manual Initiation switch and push button channels introduce signals into the RHR Shutdown Cooling System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four switch and push buttons (with two channels per switch and push button) for the logic, two switch and push button per trip system. Eight channels of the Manual Initiation Function are available and are required to be OPERABLE in MODES 1, 2, and 3 since these are the MODES in which the RHR Shutdown Cooling System Isolation automatic Functions are required to be OPERABLE. While certain automatic Functions are required in MODES 4 and 5, the Manual Initiation Function is not required in MODES 4 and 5, since there are other means (ie., means other than the Manual Initiation switch and push buttons) to manually isolate the RHR Shutdown Cooling System from the control room.

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

This Function isolates the Group 5 valves.

ACTIONS

A Note has been provided to modify the ACTIONS related to primary containment isolation 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 primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that

(continued)

BASES

ACTIONS (continued)

allows separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 11 and 12) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be 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, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action 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 redundant automatic isolation capability being lost for the associated penetration flow path(s). The MSIVs portion of the MSL isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that both trip systems will generate a trip signal from the given Function on a valid signal. The MSL drain valves portion of the MSL isolation Functions and the other isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate a trip signal from the given Function on a valid signal. This

(continued)

BASES

ACTIONS

B.1 (continued)

ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For the MSIVs portion of Functions 1.a, 1.b, 1.d, 1.e, and 1.f, this would require both trip systems to have one channel OPERABLE or in trip. For the MSL drain valves portion of Functions 1.a, 1.b, 1.d, 1.e, and 1.f, this would require one trip system to have two channels, each OPERABLE or in trip. For the MSIVs portion of Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For the MSL drain valves portion of Function 1.c, this would require one trip system to have two channels, associated with each MSL, each OPERABLE or in trip. For the MSIVs portion of Function 1.g, this would require both trip systems to have one channel per area OPERABLE or in trip. For the MSL drain valves portion of Function 1.g, this would require one trip system to have two channels per area, each OPERABLE or in trip. For Functions 2.a, 2.b, 3.c, 3.d, 4.f, and 5.b, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 2.c, 3.a, 3.b, 3.e, 3.f, 3.j, 3.k, 3.l, 4.a, 4.b, 4.c, 4.g, and 5.c, this would require one trip system to have one channel OPERABLE or in trip. For Functions 3.g, 3.h, 3.i, 4.d, 4.e, 5.a, 5.d, and 5.e, each Function consists of channels that monitor several different locations. Therefore, this would require one channel per location (area/room) to be OPERABLE or in trip (the channels are not required to be in the same trip system). The Condition does not include the Manual Initiation Functions (Functions 1.h, 2.d, 3.m, 4.h, and 5.f), since they are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

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

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE

(continued)

BASES

ACTIONS

C.1 (continued)

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 or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated MSLs may be isolated (Required Action D.1), and if allowed (i.e., plant safety analysis allows operation with an MSL isolated), plant operation with the MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. This Required Action will generally only be used if a Function 1.c channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow—High Function channel(s) are inoperable. Alternatively, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If the channel is not restored to OPERABLE status or 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 placing the plant in at least MODE 2 within 6 hours.

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

(continued)

BASES

ACTIONS (continued)

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operation may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channel.

For some of the Area Temperature—High Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A Area Temperature—High channel is inoperable, the A pump room area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump. For the RWCU Differential Flow—High Function, if a channel is inoperable due solely to a portion of the channel that monitors flow to the condenser being inoperable, then the affected flow path(s) may be considered isolated by isolating only the RWCU blowdown piping.

Alternatively, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

The Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact that these Functions (Manual Initiation) are not assumed in any accident or transient analysis in the USAR. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip, or any Required Action of Condition F or G is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in 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.

I.1 and I.2

If the channel is not restored to OPERABLE status within the allowed Completion Time, the associated SLC subsystem(s) is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the associated SLC subsystem inoperable or isolating the RWCU System.

The Completion Time of 1 hour is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated). ACTIONS must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

(continued)

BASES (continued)

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 also 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 isolation 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 analyses (Refs. 11 and 12) 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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.2

This Surveillance verifies that, when the Allowable Value for the Main Steam Line Tunnel Lead Enclosure Temperature—High Function is adjusted based on the formula in footnote (b) to Table 3.3.6.1-1, the actual ambient temperature, as measured by the Main Steam Line Tunnel Lead Enclosure Temperature—High Function channels, is greater than or equal to the ambient temperature (T_{amb}) used to adjust the Allowable Value. Only the OPERABLE Main Steam Line Tunnel Lead Enclosure Temperature—High Function channels are required to be verified. As stated in the Note to the SR, the SR is only required to be met when the Allowable Value is adjusted in accordance with Table 3.3.6.1-1, footnote (b), since the normal Allowable Value is based on a sufficiently low ambient temperature that the verification is not necessary.

The Frequency of 12 hours is based on the need to periodically monitor the ambient temperature to ensure the Allowable Value remains valid, and was chosen to coincide with the CHANNEL CHECK Frequency. As required by SR 3.0.1, the SR must also be performed prior to adjusting the Allowable Value, since the Surveillance must be met at all times when the Allowable Value has been adjusted (thus to meet the SR when the Allowable Value has been adjusted, it must actually be performed prior to the adjustment).

SR 3.3.6.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. 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 described in References 11 and 12.

SR 3.3.6.1.4

The calibration of trip units consists of a test to provide a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.4 (continued)

Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 11 and 12.

SR 3.3.6.1.5

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 on the assumption of a 24 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. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.7

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists in the 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test. The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. However, failure to meet the ISOLATION SYSTEM RESPONSE TIME due to a PCIV closure time not within limits does not require the associated instrumentation to be declared inoperable; only the PCIV is required to be declared inoperable. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in Reference 13.

A Note to the Surveillance states that the response time of the sensors may be assumed to be the design sensor response time and therefore, are excluded from the ISOLATION SYSTEM RESPONSE TIME testing. This is allowed since the sensor response time for the affected Functions (Functions 1.a, 1.b, and 1.c) is a small part of the overall ISOLATION SYSTEM RESPONSE TIME (Ref. 14).

ISOLATION SYSTEM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 month test Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent.

REFERENCES

1. USAR, Table 6.2-56.

2. USAR, Section 6.2.

3. USAR, Chapter 15 and Appendix A.

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

5. USAR, Section 15.1.3.

(continued)

BASES

REFERENCES (continued)

6. USAR, Section 15.6.4.
7. USAR, Section 15.2.5.
8. USAR, Section 11.3.
9. USAR, Section 9.3.5.2.
10. 10 CFR 50.62.
11. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
12. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
13. Technical Requirements Manual.
14. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND

The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs) and starts the Standby Gas Treatment (SGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1), such that offsite radiation exposures are maintained within the requirements of 10 CFR 100 that are part of the NRC staff approved licensing basis. Secondary containment isolation and establishment of vacuum with the SGT System within the assumed time limits ensures that 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, are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) drywell pressure, (c) reactor building above the refuel floor exhaust radiation, and (d) reactor building below the refuel floor exhaust radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation parameters. In addition, manual initiation of the logic, while not required to be OPERABLE by this Specification, is also provided.

For both the Reactor Vessel Water Level—Low Low, Level 2 and Drywell Pressure—High Functions, the secondary containment isolation instrumentation logic receives input from four channels. The output from these channels are arranged into two two-out-of-two trip systems. For both the Reactor Building Above the Refuel Floor Exhaust Radiation—

(continued)

BASES

BACKGROUND (continued)

High and the Reactor Building Below the Refuel Floor Exhaust Radiation—High Functions, the secondary containment isolation instrumentation logic receives input from two channels. The output from these channels are arranged into two one-out-of-one trip systems. In addition to the isolation function, the SGT subsystems are initiated. There are two SGT subsystems with one subsystem being initiated by each trip system. Automatically isolated secondary containment penetrations are isolated by two isolation valves. Each trip system initiates isolation of one of two valves so that operation of either trip system isolates the penetrations.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves and start the SGT System to limit offsite doses.

Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses.

The secondary containment isolation instrumentation satisfies Criterion 3 of Reference 3. Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the secondary containment isolation instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions. Each Function must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.6.2-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Function specified in the Table. Nominal trip setpoints are specified in setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions when SCIVs and the SGT System are required.

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

1. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (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. An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level—Low Low, Level 2 Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation of systems on Reactor Vessel Water Level—Low

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level—Low Low, Level 2 (continued)

Low, Level 2 support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 1).

Reactor Vessel Water Level—Low Low, Level 2 signals are initiated from differential pressure transmitters 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. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low, Level 2 Allowable Value was chosen to be the same as the High Pressure Core Spray (HPCS)/Reactor Core Isolation Cooling (RCIC) Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System Instrumentation"), since this could indicate the capability to cool the fuel is being threatened.

The Reactor Vessel Water Level—Low Low, Level 2 Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required. In addition, the Function is also required to be OPERABLE during operations with a potential for draining the reactor vessel (OPDRVs) to ensure that offsite dose limits are not exceeded if core damage occurs.

2. Drywell Pressure—High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the SGT System are

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure—High (continued)

initiated in order to minimize the potential of an offsite dose release. The isolation and initiation of systems on Drywell Pressure—High supports actions to ensure that any offsite releases are within the limits calculated in the safety analysis. However, the Drywell Pressure—High Function associated with isolation is not assumed in any USAR accident or transient analysis. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be the same as the RPS Drywell Pressure—High Function Allowable Value (LCO 3.3.1.1) since this is indicative of a loss of coolant accident.

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

3, 4. Reactor Building Above the Refuel Floor and Reactor Building Below the Refuel Floor Exhaust Radiation—High

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Exhaust Radiation—High is detected, secondary containment isolation and actuation of the SGT System are initiated to limit the release of fission products as assumed in the USAR safety analyses (Refs. 1 and 2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	3, 4. Reactor Building Above the Refuel Floor and Reactor Building Below the Refuel Floor Exhaust Radiation—High (continued) Reactor Building Above the Refuel Floor Exhaust Radiation—High signals are initiated from gaseous radiation detectors that are located on the ventilation exhaust ducting coming from the refuel floor. Reactor Building Below the Refuel Floor Exhaust Radiation—High signals are initiated from gaseous radiation detectors that are located on the ventilation exhaust ducting coming from the different areas of the secondary containment below the refuel floor. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Above the Refuel Floor Exhaust Radiation—High Function and two channels of Reactor Building Below the Refuel Floor Exhaust Radiation—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Allowable Values are chosen to promptly detect gross failure of the fuel cladding. The Exhaust Radiation—High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are required to be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.
ACTIONS	A Note has been provided to modify the ACTIONS related to secondary containment isolation 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

(continued)

BASES

ACTIONS (continued)

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 secondary containment isolation 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 secondary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be 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, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), 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 isolation capability for the associated penetration flow path(s) or a complete loss of initiation capability for the SGT System. A Function is considered to be maintaining

(continued)

BASES

ACTIONS

B.1 (continued)

isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two trip systems (Functions 1 and 2), this would require one trip system to have two channels, each OPERABLE or in trip. For the Functions with two one-out-of-one trip systems (Functions 3 and 4), this would require one trip system to have one channel OPERABLE or 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.

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time of Condition A or B are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated penetration flow path(s) and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operations to continue. The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem.

Alternatively, declaring the associated SCIVs or SGT subsystem inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

(continued)

BASES

ACTIONS

C.1.1, C.1.2, C.2.1, and C.2.2 (continued)

One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without challenging plant systems.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

The Surveillances are also 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 isolation 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 Action(s) taken. This Note is based on the reliability analysis (Refs. 4 and 5) 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 SCIVs will isolate the associated penetration flow paths and the SGT System will initiate when necessary.

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 indicated parameter for one instrument 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.1 (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 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.

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

The Frequency of 92 days is based upon the reliability analysis of References 4 and 5.

SR 3.3.6.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 4 and 5.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.4

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 a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.2.5

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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. 10 CFR 50.36(c)(2)(ii).
4. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
5. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentations Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Envelope Filtration (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. Two independent CREF subsystems are each capable of fulfilling the stated safety function. The instrumentation and controls for the CREF System automatically initiate action to start and direct flow through the control room outdoor air special filter trains and maintain pressurized the main control room envelope to minimize the consequences of radioactive material in the control room environment.

In the event of a loss of coolant accident (LOCA) signal (Reactor Vessel Water Level—Low Low, Level 2 or Drywell Pressure—High) or Main Control Room Ventilation Radiation Monitor—High signal, the CREF System is automatically started in the emergency pressurization mode. A portion of the control room envelope air is then recirculated through the charcoal filter, and sufficient outside air is drawn in through the two outside air intakes to keep the control room envelope slightly pressurized with respect to the outside atmosphere.

The CREF System instrumentation has two trip systems: one trip system initiates one CREF subsystem, while the second trip system initiates the other CREF subsystem (Ref. 1). Each trip system receives input from the Functions listed above. The Functions are arranged as follows for each trip system. The Reactor Vessel Water Level—Low Low, Level 2 and Drywell Pressure—High are arranged together in a one-out-of-two taken twice logic. The Main Control Room Ventilation Radiation Monitor—High is arranged in a two-out-of-two logic. The channels include electronic equipment (e.g., trip units) 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.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CREF System to maintain the habitability of the control room envelope is explicitly assumed for certain accidents as discussed in the USAR safety analyses (Refs. 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, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A.

CREF System instrumentation satisfies Criterion 3 of Reference 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 a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. 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. These nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint that is 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., reactor vessel water level), 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 by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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

1. Reactor Vessel Water Level—Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that the capability to cool 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 Low, Level 2 signals are initiated from four differential pressure transmitters 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. Four channels of Reactor Vessel Water Level—Low Low, Level 2 Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation. The Allowable Value for the Reactor Vessel Water Level—Low Low, Level 2 is chosen to be the same as the Secondary Containment Isolation Reactor Vessel Water Level—Low Low, Level 2 Allowable Value (LCO 3.3.6.2).

The Reactor Vessel Water Level—Low Low, Level 2 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. In MODES 4 and 5, at times other than during OPDRVs, the probability of a vessel draindown event releasing radioactive material into the environment, or of a LOCA, is minimal. Therefore this Function is not required. In addition, the Main Control Room Ventilation Radiation Monitor—High Function provides adequate protection.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). 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.

Drywell Pressure—High signals are initiated from four pressure transmitters that sense drywell pressure. Four channels of Drywell Pressure—High Function are available (two channels per trip system) and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation.

The Drywell Pressure—High Allowable Value was chosen to be the same as the Secondary Containment Isolation Drywell Pressure—High Allowable Value (LCO 3.3.6.2).

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during 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. Main Control Room Ventilation Radiation Monitor—High

High radiation within the common intake duct of the main control room outside air intakes is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When main control room ventilation high radiation is detected (above measured background), the CREF System is automatically initiated in the emergency pressurization mode since this radiation release could result in radiation exposure to control room personnel.

The Main Control Room Ventilation Radiation Monitor—High Function consists of four independent monitors. Four channels of Main Control Room Ventilation Radiation Monitor—High Function are available and are required to be

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Main Control Room Ventilation Radiation Monitor—High (continued)

OPERABLE to ensure that no single instrument failure can preclude CREF System initiation. The Allowable Value was selected to ensure protection of the control room personnel.

The Main Control Room Ventilation Radiation Monitor—High Function is required to be OPERABLE in MODES 1, 2, and 3, and during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel in the secondary containment to ensure that control room personnel are protected during a LOCA, fuel handling event, or a vessel draindown event. During MODES 4 and 5, when these specified conditions are not in progress (e.g., CORE ALTERATIONS), the probability of a LOCA 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

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.7.1-1. The applicable Condition specified in the Table is Function dependent. Each time an inoperable channel is discovered, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 24 hours has been shown to be acceptable (Refs. 5 and 6) 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. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate. If the Function is not maintaining CREF System initiation capability, the CREF System must be declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action B.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable, untripped channels in the same Function in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 12 hours has been shown to be acceptable (Refs. 5 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. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CREF System initiation capability), the 12 hour allowance of Required Action C.2 is not appropriate. If the Function is not maintaining CREF System initiation capability, the CREF System must be declared inoperable within 1 hour of discovery of loss of CREF System initiation capability in both trip systems (Required Action C.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the CREF System cannot be automatically initiated due to inoperable, untripped Drywell Pressure—High channels in both trip systems. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoring or tripping of channels.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition, per Required Action C.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

With any Required Action and associated Completion Time not met, the associated CREF subsystem must be placed in the emergency pressurization mode of operation (Required Action D.1) to ensure that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the CREF subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the CREF subsystem. Alternately, if it is not desired to start the subsystem, the CREF subsystem associated with inoperable, untripped channels must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREF subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels, or for placing the associated CREF subsystem in operation.

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 also 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.1 (continued)

CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument 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 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 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. 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

The calibration of trip units provides a check of the actual trip setpoints. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value. If the trip setting is discovered to be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1.3 (continued)

less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.7.1.4

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 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.7.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.2, "Control Room Envelope Filtration (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

(continued)

BASES (continued)

REFERENCES

1. USAR, Figure 9.4-4.

2. USAR, Section 6.4.

3. USAR, Chapter 15.

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

5. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

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

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

B 3.3 INSTRUMENTATION

B 3.3.7.2 Mechanical Vacuum Pump Isolation Instrumentation

BASES

BACKGROUND

The Mechanical Vacuum Pump Isolation Instrumentation initiates a trip of the main condenser mechanical vacuum pumps and isolation of the associated isolation valve following events in which main steam line radiation exceeds predetermined values. Tripping and isolating the mechanical vacuum pumps limits the offsite doses in the event of a control rod drop accident (CRDA).

The Mechanical Vacuum Pump Isolation Instrumentation (Refs. 1 and 2) includes detectors, monitors, and relays that are necessary to cause initiation of a mechanical vacuum pump isolation. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the mechanical vacuum pump isolation logic.

The isolation logic consists of two independent trip systems, with two channels of Main Steam Line Radiation—High in each trip system. Each trip system is a one-out-of-two logic for this Function. Thus, either channel of Main Steam Line Radiation—High in each trip system is needed to trip a trip system. The outputs of the channels in a trip system are combined in a one-out-of-two taken twice logic so that both trip systems must trip to result in an isolation signal.

There is one isolation valve and two mechanical vacuum pump breakers associated with this Function.

APPLICABLE SAFETY ANALYSES

The Mechanical Vacuum Pump Isolation Instrumentation is assumed in the safety analysis for the CRDA. The Mechanical Vacuum Pump Isolation Instrumentation initiates a trip and isolation of the mechanical vacuum pumps to limit offsite doses resulting from fuel cladding failure in a CRDA (Ref. 3).

The mechanical vacuum pump isolation satisfies Criterion 3 of Reference 4.

(continued)

BASES (continued)

LCO

The OPERABILITY of the mechanical vacuum pump isolation is dependent on the OPERABILITY of the individual Main Steam Line Radiation—High instrumentation channels, which must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.7.2.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated isolation valve and mechanical vacuum pump breakers.

An Allowable Value is specified for the Main Steam Line Radiation—High isolation Function specified in the LCO. The nominal trip setpoint is specified in the setpoint calculations. The nominal setpoint is selected to ensure that the setpoint does 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. The trip setpoint is that predetermined value of output at which an action should take place. The setpoint is compared to the actual process parameter (i.e., main steam line radiation) and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip auxiliary unit) changes state. The analytic limit is derived from the limiting value of the process parameter obtained from the safety analysis. The Allowable Value is derived from the analytic limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoint is derived from the analytical limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoint is also derived from the Allowable Value in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoint is used. In addition, both the Allowable Value and trip setpoint may have additional conservatisms.

APPLICABILITY

The mechanical vacuum pump isolation is required to be OPERABLE in MODES 1 and 2, when any mechanical vacuum pump is in service (i.e., taking a suction on the main condenser)

(continued)

BASES

APPLICABILITY (continued)

and any main steam line not isolated, to mitigate the consequences of a postulated CRDA. In this condition fission products released during a CRDA could be discharged directly to the environment. Therefore, the mechanical vacuum pump isolation is necessary to assure conformance with the radiological evaluation of the CRDA. In MODE 3, 4 or 5 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. When the mechanical vacuum pump is not in service or the main steam lines are isolated in MODE 1 or 2, fission product releases via this pathway would not occur.

ACTIONS

A Note has been provided to modify the ACTIONS related to Mechanical Vacuum Pump Isolation 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 Mechanical Vacuum Pump Isolation 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 Mechanical Vacuum Pump Isolation Instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with mechanical vacuum pump isolation capability maintained (refer to Required Action B.1 Bases), the Mechanical Vacuum Pump Isolation Instrumentation is capable of performing the intended function. However, the reliability and redundancy of the Mechanical Vacuum Pump Isolation Instrumentation is reduced, such that a single failure in one of the remaining channels could result in the inability of the Mechanical Vacuum Pump Isolation Instrumentation to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities affecting multiple channels, and the low probability of an event requiring the initiation of

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

mechanical vacuum pump isolation, 12 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status (Required Action A.1). Alternately, the inoperable channel, may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable isolation valve or mechanical vacuum pump breaker, since this may not adequately compensate for the inoperable valve or breaker (e.g., the valve may be inoperable such that it will not close). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in loss of condenser vacuum), or if the inoperable channel is the result of an inoperable valve or breaker, Condition C must be entered and its Required Actions taken.

B.1

Condition B is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system result in not maintaining mechanical vacuum pump isolation capability. The mechanical vacuum pump isolation capability is maintained when sufficient channels are OPERABLE or in trip such that the Mechanical Vacuum Pump Isolation Instrumentation will generate a trip signal from a valid Main Steam Line Radiation—High signal, and the isolation valve will close and mechanical vacuum pump breakers will open. This would require both trip systems to have one channel OPERABLE or in trip, and the mechanical vacuum pump isolation valve or mechanical vacuum pump breakers to be OPERABLE.

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

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours (Required Action C.4). Alternately, the associated mechanical vacuum pump may be removed from service since this performs the intended function of the instrumentation (Required Actions C.1 and C.2). An additional option is provided to isolate the main steam lines (Required Action C.3), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, or to remove the mechanical vacuum pump from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 the associated Conditions and Required Actions may be delayed for up to 6 hours provided mechanical vacuum pump isolation trip capability is maintained. 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. 5) 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 mechanical vacuum pumps will trip and isolate when necessary.

SR 3.3.7.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.1 (continued)

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 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 required channels of this LCO.

SR 3.3.7.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. 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 5.

SR 3.3.7.2.3

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.3 (continued)

The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.7.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breakers and isolation valve 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 a breaker or the isolation valve is incapable of operating, the associated instrument channel(s) would be inoperable.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

REFERENCES

1. USAR, Section 7.3.1.1.2.
2. USAR, Section 10.4.2.
3. USAR, Section 15.4.9.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDC-30851-P-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. 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 the Division 1, 2, and 3 buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage.

Each Division 1, 2 and 3, 4.16 kV Emergency Bus Loss of Voltage Function and Degraded Voltage Function is monitored by three separate undervoltage relays, one relay per phase (Ref. 1). These relay outputs are arranged in a two-out-of-three logic configuration for each division. The 4.16 kV Emergency Bus Undervoltage and Degraded Voltage Function signals provide inputs to their respective Bus Undervoltage and Degraded Voltage—Time Delay Functions. Each Division 1, 2, and 3 emergency bus has one Loss of Voltage—Time Delay relay. The Division 1 and 2 Degraded Voltage Function output utilizes two time delay relays, one time delay for a LOP with a loss of coolant accident (LOCA) signal and the other a LOP without a LOCA signal. The Division 3 Degraded Voltage Function has only one Time Delay Function. When a 4.16 kV Emergency Bus Loss of Voltage or Degraded Voltage Function setpoint has been exceeded and the respective time delay completed, the time delay relay actuates and sends a LOP signal to the respective bus load shedding control scheme, which starts the associated DG, provides a closure signal for the DG output breaker, opens both offsite circuit supply breakers, and for Division 1 and 2 only, sheds all loads on the 4.16 kV emergency bus, including the stub bus (except the 600 V load centers).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for the 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 analyzed accidents in References 2, 3, and 4 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 two of the three DGs based on the loss of offsite power coincident with a LOCA. 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 Reference 5.

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. 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 setpoint does 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. 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., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device 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 by accounting

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

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

<u>4.16 kV Emergency Bus Undervoltage</u>

<u>1.a, 1.b, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)</u>

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 prior to the voltage on the bus dropping below the minimum Loss of Voltage Function Allowable Value but after the voltage drops below the maximum Loss of Voltage Function Allowable Value (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a, 1.b, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) (continued)

Three channels of Division 1, 2 and 3, 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)—4.16 kV Basis Function per associated emergency bus are available, but only two channels of Loss of Voltage—4.16 kV Basis per 4.16 kV emergency bus is required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of Loss of Voltage—Time Delay Function per associated emergency bus is available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements ensure that no single instrument failure can preclude the DG function (Since a failure of a required loss of voltage channel or a time delay channel will only impact the ability of one of the three DGs to start, and only two DGs are credited in the accident analyses, the DG function is still maintained). Refer to LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

1.c, 1.d, 1.e, 2.c, 2.d. 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, power may be insufficient for starting large motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power prior to the voltage on the bus dropping below the minimum Degraded Voltage Function Allowable Value but after the voltage drops below the maximum Degraded Voltage Function Allowable Value (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are 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 Values are 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.

Three channels of the Division 1, 2 and 3, 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)—4.16 kV Basis Function

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 1.e, 2.c, 2.d. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

per associated emergency bus are available, but only two channels of the Degraded Voltage—4.16 kV Basis per 4.16 kV emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of each Division 1 and 2 Degraded Voltage—Time Delay, No LOCA Function and Degraded Voltage—Time Delay, LOCA Function per associated emergency bus, is available and required to be OPERABLE when the associated DG is required to be OPERABLE. One channel of the Division 3 Degraded Voltage—Time Delay Function is available and required to be OPERABLE when the associated DG is required to be OPERABLE. These requirements ensure that no single instrument failure can preclude the DG function (Since a failure of a required degraded voltage channel or a time delay channel will only impact the ability of one of the three DGs to start, and only two DGs are credited in the accident analyses, the DG function is still maintained). 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 required channels of a Function inoperable, the Function may not be capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the

(continued)

BASES

ACTIONS

A.1 (continued)

allowable out of service time, the channel must be 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, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

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 is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are 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, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

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 2 hours provided the associated Function maintains LOP initiation capability. LOP initiation capability is maintained provided bus load shedding control scheme can be initiated by the Loss of Voltage or Degraded Voltage Functions for two of the three 4.16 kV emergency buses. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

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

SR 3.3.8.1.2

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 on the assumption of a 24 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.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 8.3.1.1.2.
2. USAR, Section 5.2.
3. USAR, Section 6.3.
4. USAR, Chapter 15.
5. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring—Logic

BASES

BACKGROUND

The RPS Electric Power Monitoring—Logic System is provided to isolate the RPS logic bus from the uninterruptible power supply (UPS) set or an alternate AC power supply in the event of overvoltage, undervoltage, or underfrequency. The UPS set can be supplied by the normal AC source or by the backup DC source. This system protects the loads connected to the RPS logic bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path for the essential safety circuits. Some of the essential equipment powered from the RPS logic buses includes the RPS logic, main steam isolation valve trip solenoids, and various valve isolation logic.

The RPS Electric Power Monitoring—Logic assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two UPS sets or alternate power supplies and will de-energize its respective RPS logic 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—Logic System (e.g., both inseries electric power monitoring assemblies), the RPS logic bus loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the MSIV trip solenoids and other Class 1E devices.

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

In the event of an overvoltage condition, the RPS and isolation logic relays, as well as the main steam isolation valve trip 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 logic bus and its UPS set or its

(continued)

BASES

BACKGROUND (continued)	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 UPS set or the alternate power supply exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes power to the associated RPS logic bus.
APPLICABLE SAFETY ANALYSES	RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS logic buses can perform its intended function. RPS electric power monitoring provides protection to the RPS (except the scram solenoids) and other systems that receive power from the RPS logic buses, by disconnecting the RPS logic buses from the power supply under specified conditions that could damage the RPS logic bus powered equipment. RPS Electric Power Monitoring—Logic satisfies Criterion 3 of Reference 2.
LCO	The OPERABILITY of each RPS electric power monitoring assembly (RPS logic bus) is dependent upon 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 RPS logic bus. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly (RPS logic bus) failure can preclude the function of RPS logic bus powered components. Each of the electric power monitoring assembly (RPS logic bus) trip logic setpoints are required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each RPS electric power monitoring assembly (RPS logic bus) trip logic (refer to SR 3.3.8.2.2). 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

(continued)

BASES

LCO (continued)

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 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 limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The Allowable Values for the instrument settings are based on the RPS logic bus providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V (+ 10 V, - 15 V) (to MSIV trip 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 RPS logic buses being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies (RPS logic bus) is essential to disconnect the RPS logic bus powered components from the UPS set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS logic bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies (RPS logic bus) is required when the RPS logic bus powered components are required to be OPERABLE. This results in the RPS Electric

(continued)

BASES

APPLICABILITY (continued)

Power Monitoring—Logic System OPERABILITY being required in MODES 1, 2, and 3, MODES 4 and 5 with both residual heat removal (RHR) shutdown cooling suction isolation valves open, MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, and during operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

A.1

If one RPS electric power monitoring assembly for an RPS logic bus is inoperable, or one RPS electric power monitoring assembly for each RPS logic bus is inoperable, the OPERABLE assembly will still provide protection to the RPS logic bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring—Logic System are reduced and only a limited time (72 hours) is allowed to restore the inoperable assembly(s) to OPERABLE status. If the inoperable assembly(s) cannot be restored to OPERABLE status, Condition C, D, E, or F, as applicable, must be entered and its Required Actions taken.

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—Logic protection occurring during this period. It also allows time for plant operations personnel to take corrective actions.

B.1

If both power monitoring assemblies for an RPS logic bus are inoperable, or both power monitoring assemblies for each RPS logic bus are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each RPS logic bus. If one inoperable assembly for each RPS logic bus cannot be restored to OPERABLE status, Condition C, D, E, or F, as applicable, must be entered and its Required Actions taken. 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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, a plant shutdown must be performed. 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 logic bus loads (e.g., scram of control rods and isolation of MSIVs) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours and in 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.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5 with both RHR shutdown cooling suction isolation valves open, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for each RPS logic bus (Required Action D.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2). Required Action D.1 is provided because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

E.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 E.1). This Required Action 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.

(continued)

BASES

ACTIONS (continued)

F.1.1, F.1.2, F.2.1, F.2.2, F.3.1, and F.3.2

If any Required Action and associated Completion Time of Condition A or B are not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, the ability to isolate the secondary containment and start the Standby Gas Treatment (SGT) and Control Room Envelope Filtration (CREF) Systems cannot be ensured. Therefore, actions must be immediately performed to ensure the ability to maintain the secondary containment and CREF System functions. Isolating the affected penetration flow path(s) and starting the associated SGT and CREF subsystems (Required Actions F.1.1, F.2.1, and F.3.1) performs the intended function of the instrumentation the RPS electric power monitoring assemblies is protecting, and allows operations to continue.

Alternatively, immediately declaring the associated secondary containment isolation valves, SGT subsystem, or CREF subsystem inoperable (Required Actions F.1.2, F.2.2, and F.3.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2, LCO 3.6.4.3, and LCO 3.7.2) provide appropriate actions for the inoperable components.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when an RPS electric power monitoring assembly 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 other RPS electric power monitoring assembly for the associated RPS logic bus maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the assembly must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This 6 hour allowance is acceptable since it does not significantly reduce the probability that the RPS electric power monitoring assembly function will initiate when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 184 day Frequency is based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.2.2

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 upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

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 circuit breaker. 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.3.8.2.3 (continued) Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.
REFERENCES	1. USAR, Section 8.3.1.1.3. 2. 10 CFR 50.36(c)(2)(ii). 3. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

B 3.3 INSTRUMENTATION

B 3.3.8.3 Reactor Protection System (RPS) Electric Power Monitoring—Scram Solenoids

BASES

BACKGROUND

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

The RPS Electric Power Monitoring—Scram Solenoids assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or alternate power supplies and will de-energize its respective RPS scram solenoid 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—Scram Solenoids System (e.g., both inseries electric power monitoring assemblies), the RPS scram solenoids may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids.

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 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 scram solenoid bus and its MG set or 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

(continued)

BASES

BACKGROUND (continued)	power monitoring assembly. If the output of the MG set or the alternate power supply exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes power to the associated RPS scram solenoid bus.
APPLICABLE SAFETY ANALYSES	RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the scram solenoids can perform their intended function. RPS electric power monitoring provides protection to the scram solenoids by disconnecting the RPS scram solenoid buses from the power supply under specified conditions that could damage the RPS scram solenoids. RPS Electric Power Monitoring—Scram Solenoids satisfies Criterion 3 of Reference 2.
LCO	The OPERABILITY of each RPS electric power monitoring assembly (RPS scram solenoid bus) is dependent upon 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 RPS scram solenoid bus. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly (RPS scram solenoid bus) failure can preclude the function of RPS scram solenoids. Each of the electric power monitoring assembly (RPS scram solenoid bus) trip logic setpoints are required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each RPS electric power monitoring assembly (RPS scram solenoid bus) trip logic (refer to SR 3.3.8.3.2). 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

(continued)

BASES

LCO (continued)

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 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 limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms.

The Allowable Values for the instrument settings are based on the RPS scram solenoid buses providing ≥ 57 Hz and 115 V ± 10 V to the 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 RPS scram solenoid buses being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies (RPS scram solenoid bus) is essential to disconnect the RPS scram solenoids 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 scram solenoid bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies (RPS scram solenoids) is required when the RPS scram solenoid bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring—Scram

(continued)

BASES

APPLICABILITY (continued)

Solenoids System OPERABILITY being required in MODES 1 and 2, and 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 RPS scram solenoid bus is inoperable, or one RPS electric power monitoring assembly for each RPS scram solenoid bus is inoperable, the OPERABLE assembly will still provide protection to the RPS scram solenoids under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring—Scram Solenoids System are reduced and only a limited time (72 hours) is allowed to restore the inoperable assembly(s) to OPERABLE status. If the inoperable assembly(s) cannot be restored to OPERABLE status, the associated RPS scram solenoid bus must be removed from service (Required Action A.1). This places the RPS scram solenoid bus in a safe condition.

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—Scram Solenoids 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.

Alternatively, if it is not desired to remove the RPS scram solenoid bus(es) from service (e.g., as in the case where removing the RPS scram solenoid bus(es) from service would result in a scram), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an RPS scram solenoid bus are inoperable, or both power monitoring assemblies for each RPS scram solenoid bus are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each RPS scram solenoid bus. If one inoperable assembly for each RPS scram solenoid bus cannot be restored to

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE status, the associated RPS scram solenoid bus must be removed from service within 1 hour (Required Action B.1). 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 RPS scram solenoid bus(es) from service (e.g., as in the case where removing the RPS scram solenoid bus(es) from service would result in a scram), 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. 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 scram solenoids (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 condition from full power conditions 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. This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS scram solenoids (e.g., scram of control rods) is not required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when an RPS electric power monitoring assembly 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 other RPS electric power monitoring assembly for the associated RPS scram solenoid bus maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the assembly must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This 6 hour allowance is acceptable since it does not significantly reduce the probability that the RPS electric power monitoring assembly function will initiate when necessary.

SR 3.3.8.3.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 184 day Frequency is based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.3.2

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 upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.3.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3.3 (continued)

signal, the logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for 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 24 month Frequency.

REFERENCES

1. USAR, Section 8.3.1.1.3.
2. 10 CFR 50.36(c)(2)(ii).
3. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes heat at a faster rate from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The Reactor Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains a two speed motor driven recirculation pump, a flow control valve, associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section and result in partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

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BASES

BACKGROUND (continued)

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 55 to 100% RTP) without having to move control rods and disturb desirable flux patterns. In addition, the combination of core flow and THERMAL POWER is normally maintained such that core thermal-hydraulic oscillations do not occur. These oscillations can occur during two-loop operation, as well as single-loop and no-loop operation. Plant procedures include requirements of this LCO as well as other vendor and NRC recommended requirements and actions to minimize the potential of core thermal-hydraulic oscillations.

Each recirculation loop is manually started from the control room. The recirculation flow control valves provide regulation of individual recirculation loop drive flows. The flow in each loop can be manually or automatically controlled.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Recirculation System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 2). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement.

The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 3), which are analyzed in Chapter 15 of the USAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Ref. 4).

The transient analyses in Chapter 15 of the USAR have also been performed for single recirculation loop operation (Ref. 4) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System average power range monitor (APRM) and the Rod Block Monitor Allowable Values is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR limits for single loop operation are specified in the COLR. The APRM Flow Biased Simulated Thermal Power—Upscale Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." The Rod Block Monitor—Upscale Allowable Value is in LCO 3.3.2.1, "Control Rod Block Instrumentation."

Safety analyses performed in Refs. 1 and 4 implicitly assure core conditions are stable. However, at the high power/low flow corner of the operating domain, a small probability of limit cycle neutron flux oscillations exists (Ref. 5) depending on combinations of operating conditions (e.g., power shape, bundle power, and bundle flow).

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BASES

APPLICABLE SAFETY ANALYSES (continued)

General Electric Service Information Letter (SIL) No. 380 (Ref. 5) addressed boiling instability and made several recommendations. In this SIL, the power-to-flow map was divided into several regions of varying concern. It also discussed the objectives and philosophy of "detect and suppress."

NRC Generic Letter 86-02 (Ref. 6) discussed the GE stability methodology and stated that due to uncertainties, General Design Criteria 10 and 12 could not be met using available analytical procedures on a BWR. The letter discussed SIL 380 and stated that General Design Criteria 10 and 12 could be met by imposing SIL 380 recommendations in operating regions of potential instabilities. The NRC concluded that regions of potential instability constituted decay ratios of 0.8 and greater by the GE methodology.

GE issued Reference 5 to address the stability issue and to establish the stability zones. Subsequently, the zones have been re-established due to power uprate. Figure 3.4.1-1 has been divided into two major zones; the "Unrestricted Zone" and the "Restricted Zone." Continuous operation is permitted in the "Unrestricted Zone" while limited operation is permitted in the "Restricted Zone" due to the potential for thermal-hydraulic oscillations. In addition, the actions to take when operating with one or two recirculation loops in the "Restricted Zone" is based upon core flow being > 39% of total core flow or ≤ 39% of total core flow. The 39% value is equivalent to the minimum core flow for two recirculation pumps operating at high speed with minimum flow control valve position.

Recirculation loops operating satisfies Criterion 2 of Reference 7.

LCO

Two recirculation loops are normally required to be in operation with their flows matched within the limits specified in SR 3.4.1.2 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternatively, with only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER

(continued)

BASES

LCO (continued)

RATIO (MCPR)"), APRM Flow Biased Simulated Thermal Power—Upscale Allowable Value (LCO 3.3.1.1), and the Rod Block Monitor—Upscale Allowable Value (LCO 3.3.2.1) must be applied to allow continued operation consistent with the assumptions of Reference 4. In addition, during two-loop and single-loop operation, the combination of core flow and THERMAL POWER must be in the "Unrestricted Zone" of Figure 3.4.1-1 to ensure core thermal-hydraulic oscillations do not occur. The "Unrestricted Zone" includes all the area to the right of the "Restricted Zone" boundary. The full power-to-flow map is not shown to enhance the readability of the bounds of the "Restricted Zone."

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1, A.2, and A.3

With no recirculation loops in operation, the probability of thermal-hydraulic oscillations is greatly increased. Therefore, action must be taken as soon as practicable to ensure operation is within the "Unrestricted Zone" of Figure 3.4.1-1, assuring the stability concerns are addressed. The 2 hour Completion Time provides a reasonable amount of time to restore operation to the "Unrestricted Zone" of Figure 3.4.1-1. This may be performed by reducing THERMAL POWER by inserting control rods.

The plant is also required to be brought to at least MODE 2 within 6 hours and to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and transients and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With one or two recirculation loops in operation in the "Restricted Zone" of Figure 3.4.1-1 and core flow > 39% of rated core flow, the plant is operating in a region where the potential for thermal-hydraulic oscillations exists. To ensure oscillations are not occurring, the APRM and LPRM neutron flux noise levels must be determined to be ≤ 3 times the baseline noise levels. For the LPRM neutron flux noise determination, detector levels A and C of one LPRM string per core octant plus detectors A and C of one LPRM string in the center of the core are monitored.

Baseline noise levels are determined uniquely for each cycle during the first operation in the "Restricted Zone" following a refueling outage. This initial baseline is then used for comparison to all subsequent neutron flux noise levels during operation in this zone.

A determination of APRM and LPRM neutron flux noise levels once per 8 hours provides frequent periodic information relative to established baseline noise levels that indicate stable steady state operation. A determination of these noise levels within 30 minutes after an increase of ≥ 5% RTP provides a more frequent indication of the stability of operation following any significant potential for change of the thermal hydraulic properties of the system. These Frequencies provide early detection of neutron flux oscillations due to core thermal hydraulic instabilities.

In addition, core flow is also required to be determined every 12 hours. This will ensure that the operator periodically monitors the core flow and, if core flow decreases to ≤ 39% of rated core flow, the proper Condition is entered (Condition D). The periodic Completion Time is based on operating experience and the operator's inherent knowledge of reactor status, including changes in core flow.

C.1

If evidence of approaching instability occurs (i.e., APRM or LPRM neutron flux levels exceed three times the established baseline levels), action must be initiated as soon as practicable to restore the APRM and LPRM neutron flux levels

(continued)

BASES

ACTIONS

C.1 (continued)

to $\leq$ 3 times the established baseline levels. This can be done by increasing core flow or by reducing THERMAL POWER. The allowed 2 hour Completion Time is reasonable, based on operating experience, to restore plant parameters in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or two recirculation loops in operation in the "Restricted Zone" of Figure 3.4.1-1, and core flow $\leq$ 39% of rated core flow, the plant is operating in a region where the potential for thermal-hydraulic oscillations is increased and sufficient margin may not be available for operator response to suppress potential thermal-hydraulic oscillations. As a result, action must be taken as soon as practicable to restore operation to > 39% of rated core flow or to the "Unrestricted Zone" of Figure 3.4.1-1. This can be accomplished by either decreasing THERMAL POWER with control rod insertion or increasing core flow with recirculation flow control valve manipulation. The starting or shifting of a recirculation pump shall not be used as a means to increase core flow > 39% of rated core flow. The 4 hour Completion Time provides a reasonable amount of time to complete the Required Action.

E.1 and F.1

With both recirculation loops operating but the flows not matched, the flows must be matched within 2 hours. If matched flows are not restored, the recirculation loop with lower flow must be declared "not in operation," as required by Required Action E.1. This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing flow control valve position to re-establish forward flow or by tripping the pump.

(continued)

BASES

ACTIONS

E.1 and F.1 (continued)

With the requirements of the LCO not met for reasons other than Condition A, B, C, D, or E (e.g. one loop is "not in operation"), the recirculation loops must be restored to operation with matched flows within 4 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits for greater than 2 hours (i.e. Required Action E.1 has been taken). Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to the APLHGR and MCPR operating limits and RPS and RBM Allowable Values, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 hour and 4 hour Completion Times are based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

G.1

If the Required Action and associated Completion Time of Condition F is not met, the unit is required to be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the combination of core flow and THERMAL POWER are within appropriate limits to prevent uncontrolled thermal-hydraulic oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal-hydraulic instability. Figure 3.4.1-1 is based on guidance provided in References 5, 6, and 7. The 12 hour Frequency is based on operating experience and the operator's inherent knowledge of the reactor status, including significant changes in THERMAL POWER and core flow.

SR 3.4.1.2

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., effective core flow < 70% of rated core flow), the APLHGR and MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when effective core flow is < 70% of rated core flow. The jet pump loop flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop. The effective core flow shall be calculated by assuming both loops are at the smaller value of the two jet pump loop flows.

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. (However, for the purpose of performing Required Action B.2 the flow rate of both loops shall be used). This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.3 and Appendix A Section 6.
2. USAR, Section 6.3.3.7.
3. USAR, Section 5.4.1.3.
4. USAR Chapter 15B.
5. GE Service Information Letter No. 380, "BWR Core Thermal Hydraulic Stability," Revision 1, February 10, 1984.
6. NRC Generic Letter 86-02, "Technical Resolution of Generic Issue B-19, Thermal Hydraulic Stability," January 22, 1986.
7. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Flow Control Valves (FCVs)

BASES

BACKGROUND

The Reactor Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how this affects the design basis transient and accident analyses. The FCVs are part of the Reactor Recirculation System.

The Recirculation Flow Control System consists of the electronic and hydraulic components necessary for the positioning of the two hydraulically actuated FCVs. The recirculation loop flow rate can be rapidly changed within the expected flow range, in response to rapid changes in system demand. Limits on the system response are required to minimize the impact on core flow response during certain accidents and transients. Control logic will generate an FCV "motion inhibit" signal in response to any one of several hydraulic power unit or analog control circuit failure signals. The "motion inhibit" signal causes hydraulic power unit shutdown and hydraulic isolation such that the FCVs fail "as is."

APPLICABLE SAFETY ANALYSES

The FCV stroke rate is limited to ≤ 11% per second in the opening and closing directions on a control signal failure of maximum demand. This stroke rate is an assumption of the analysis of the recirculation flow control failures on decreasing and increasing flow (Refs. 1 and 2). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump almost immediately since it has lost suction. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds (Ref. 3), because the FCV is assumed to fail "as is" due to a motion inhibit as a result of a high drywell pressure interlock. In addition, the closure of a recirculation FCV concurrent with a loss of coolant accident (LOCA) has also been analyzed and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	found to be acceptable for a maximum closure rate of 11% of stroke per second (Ref. 3). Flow control valves satisfy Criterion 2 of Reference 4.
LCO	An FCV in each operating recirculation loop must be OPERABLE to ensure that the assumptions of the design basis transient and accident analyses are satisfied.
APPLICABILITY	In MODES 1 and 2, the FCVs are required to be OPERABLE, since during these conditions there is considerable energy in the reactor core, and the limiting design basis transients and accidents are assumed to occur. In MODES 3, 4, and 5, the consequences of a transient or accident are reduced and OPERABILITY of the flow control valves is not important.
ACTIONS	A Note has been provided to modify the ACTIONS related to FCVs. Section 1.3, Completion Times, specifies 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 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 FCVs provide appropriate compensatory measures for separate inoperable FCVs. As such, a Note has been provided that allows separate Condition entry for each inoperable FCV. <u>A.1</u> With one or two required FCVs inoperable, the assumptions of the design basis transient and accident analyses may not be met and the inoperable FCV must be returned to OPERABLE status or hydraulically locked within 4 hours. Opening an FCV faster than the limit could result in a more severe flow runout transient. Closing an FCV faster than the limit could result in a more severe coolant flow decrease transient. Both conditions could result in

(continued)

BASES

ACTIONS

A.1 (continued)

violation of the Safety Limit MCPR. The FCVs are designed to lockup (high drywell pressure interlock) under LOCA conditions. When the FCVs "lock-up," the recirculation flow coastdown is adequate and the resulting calculated clad temperatures are acceptable. In addition, it has been calculated with the FCVs closing at the specified limit, the resulting calculated clad temperatures will also be acceptable. Closing an FCV faster than the limit assumed in the LOCA analysis (Ref. 3) could affect the recirculation flow coastdown, resulting in higher peak clad temperatures. Therefore, if an FCV is inoperable, deactivating the valve will essentially lock the valve in position, which will prohibit the FCV from adversely affecting the DBA and transient analyses. Continued operation is allowed in this Condition.

The 4 hour Completion Time is a reasonable time period to complete the Required Action, while limiting the time of operation with an inoperable FCV.

B.1

If the FCVs are not deactivated ("locked up") within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours. This brings the unit to a condition where the flow coastdown characteristics of the recirculation loop are not important. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

Hydraulic power unit pilot operated isolation valves located between the servo valves and the common "open" and "close" lines are required to close in the event of a loss of hydraulic pressure. When closed, these valves inhibit FCV motion by blocking hydraulic pressure from the servo valve to the common open and close lines as well as to the alternate subloop. This Surveillance verifies FCV lockup on a loss of hydraulic pressure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.4.2.2

This SR ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.3.2.
2. USAR, Section 15.4.5.
3. USAR, Section 6.3.3.4.
4. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Jet Pumps

BASES

BACKGROUND

The Reactor Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the Reactor Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two thirds core height, the vessel can be reflooded and coolant level maintained at two thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains 10 jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet pumps satisfy Criterion 3 of Reference 2.

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Recirculation System is not required to be in operation, and when not in operation sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability to reflood during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 3). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if any two of the three specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 3 and 4). The baseline patterns were established during the startup test program. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while baselining new "established patterns", engineering judgement of the daily Surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation flow control valve (FCV) operating characteristics (jet pump loop flow versus FCV position) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship may indicate a flow restriction, loss in pump hydraulic performance, leak, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the jet pump loop flow versus FCV position relationship must be verified.

Jet pump loop flow can be determined from measurement of the recirculation loop drive flow. Once this relationship has been established, increased or reduced jet pump loop flow for the same recirculation loop drive flow may be an indication of failures in one or several jet pumps.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The jet pump diffuser to lower plenum differential pressure pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 3). Normal flow ranges and established jet pump differential pressure patterns are established by plotting historical data as discussed in Reference 3.

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

REFERENCES

1. USAR, Section 6.3.

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

3. GE Service Information Letter No. 330 including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.

(continued)

BASES

REFERENCES (continued)	4.	NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (S/RVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. (However, for the purposes of this LCO, only the safety mode is required.) In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston/cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Seven of the S/RVs that provide the safety and relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

associated with MSIV position) (Refs. 2 and 3). For the purpose of the overpressure protection analyses, 16 of the S/RVs with the highest setpoints are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the most severe pressure transient.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. References 4, 5, and 6 discuss additional events that are expected to actuate the S/RVs.

S/RVs satisfy Criterion 3 of Reference 7.

LCO

The safety function of 16 S/RVs is required to be OPERABLE. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety mode). In Reference 6, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of 16 S/RVs in the safety mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

The S/RV safety setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in References 4, 5, and 6 involving the safety mode are based on these setpoints, but also include the additional uncertainties of approximately ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the specified number of S/RVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The S/RVs may be required to provide pressure relief to limit peak reactor pressure.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If one or more required S/RVs are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This Surveillance demonstrates that the required S/RVs will open at the pressures assumed in the safety analysis of References 2 and 3. The demonstration of the S/RV safety function lift settings must be performed during shutdown, since this is a bench test, and in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is approximately ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

(continued)

BASES (continued)

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. USAR, Section 5.2.2.2.2.
3. USAR, Section A.5.2.2.2.2.
4. USAR, Chapter 15.
5. USAR, Section A.5.
6. USAR, Appendix 15C.
7. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur detrimental to the safety of the facility or the public.

A limited amount of leakage inside the drywell is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the identified LEAKAGE limit. The identified LEAKAGE limit considers RCS inventory makeup capability and drywell equipment tank capacity.

RCS operational LEAKAGE satisfies Criterion 2 of Reference 7.

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

BASES

LCO (continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell atmospheric monitoring and drywell floor drain tank fill rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Identified LEAKAGE

The identified LEAKAGE limit is based on a reasonable minimum detectable amount. The limit accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

BASES (continued)

ACTIONS

A.1

With RCS unidentified or identified LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE. However, the identified LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the leakage rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to identify the source of the leak. This will ensure the unidentified LEAKAGE increase is not due to pressure boundary LEAKAGE.

The 4 hour Completion Time is needed to properly reduce the LEAKAGE increase or identify the source before the reactor must be shut down.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.7, "RCS Leakage Detection Instrumentation." Drain tank level and flow rate are typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference 8. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. 9).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
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 Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. USAR, Section 5.2.5.5.3.
7. 10 CFR 50.36(c)(2)(ii).
8. Regulatory Guide 1.45, May 1973.
9. Generic Letter 88-01, Supplement 1, February 1992.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE."

Although this Specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System;

(continued)

BASES

BACKGROUND (continued)

c. High Pressure Core Spray System; and

d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 6.

APPLICABLE SAFETY ANALYSES

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the reactor coolant pressure boundary (RCPB) to detect PIV degradation that has the potential to cause a LOCA outside of containment.

RCS PIV leakage satisfies Criterion 2 of Reference 7.

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 4).

Reference 4 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR flowpath are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR shutdown cooling mode of operation.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. Section 1.3, Completion Times, specifies 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 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 the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate, affected RCS PIV flow paths. As such, a Note has been provided that allows separate Condition entry for each affected RCS PIV flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system OPERABILITY, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

<u>A.1 and A.2</u>

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed manual, de-activated, automatic, or check valve within

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

4 hours. Required Action A.1 and Required Action A.2 are modified by a Note stating that the valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB or the high pressure portion of the system.

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseat the leaking PIVs are taken. The 4 hours allows time for these actions and restricts the time of operation with leaking valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing another valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Required Action, the low probability of a second valve failing during this time period, and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. 8).

B.1 and B.2

If leakage cannot be reduced or the system isolated, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1 (continued)

pressure condition. As stated in the LCO Section of the Bases, the test pressure may be at a lower pressure than the maximum pressure differential (at the RCS maximum pressure of 1040 psig) provided the observed leakage rate is adjusted in accordance with Reference 4. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is only required to be performed in MODES 1 and 2. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. NUREG-0677, "The Probability of Intersystem LOCA: Impact due to Leak Testing and Operational Changes," May 1980.
6. Technical Requirements Manual.
7. 10 CFR 50.36(c)(2)(ii).
8. NEDC-31339, "BWR Owners Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," November 1986.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. The Bases for LCO 3.4.5, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of two independently monitored variables, such as drywell floor drain tank fill rate changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain tank fill rate monitoring system.

The drywell floor drain tank fill rate monitoring system monitors the LEAKAGE collected in the floor drain tank. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, component cooling water, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain tank. Leakage into the drywell floor drain system flows through a piping header that penetrates the containment wall and is then directed to the drywell floor drain tank located in the reactor building. The drywell floor drain tank is monitored by one level transmitter that supplies level indication in the main control room.

(continued)

BASES

BACKGROUND (continued)

Two drywell floor drain pumps take suction from the drywell floor drain tank and discharge to the Liquid Radioactive Waste System via the reactor building floor drain system header. The pumps alternate as lead and backup on each successive start. When a high level is reached in the floor drain tank, a level switch actuates to start the lead floor drain pump. In the event the level continues to rise, a second level switch actuates to start the backup floor drain pump. When the level decreases to a low level, both floor drain pumps are stopped. A flow indicator in the discharge line of the drywell floor drain pumps provides flow indication in the control room. In addition, a leak rate recorder is provided capable of identifying a 1 gpm change over an hour period.

The drywell atmospheric monitoring systems (particulate and gaseous) continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring systems are not capable of quantifying leakage rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour (Ref. 3). Larger changes in LEAKAGE rates are detected in proportionally shorter times.

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 4 and 5). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room.

A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of Reference 7.

(continued)

BASES (continued)

LCO

The drywell floor drain tank fill rate monitoring system is required to quantify the unidentified LEAKAGE from the RCS. The other monitoring system (particulate or gaseous) provides early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1

With the drywell floor drain tank fill rate monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell atmospheric activity monitor will provide indications of changes in leakage.

With the drywell floor drain tank fill rate monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.5.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available. Required Action A.1 is modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the drywell floor drain tank fill rate monitoring system is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

B.1 and B.2

With both gaseous and particulate drywell atmospheric monitoring channels inoperable (i.e., the required drywell atmospheric monitoring system), grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

analyzed every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the required monitors.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for restoration recognizes that at least one other form of leakage detection is available.

The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate primary containment atmospheric monitoring channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 in an orderly manner and without challenging plant systems.

D.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

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 other required instrumentation (either the drywell floor drain tank fill rate monitoring system or the drywell atmospheric monitoring channel, as applicable) is OPERABLE. Upon completion of the Surveillance, or

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring RCS leakage.

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.7.2 and SR 3.4.7.4

These SRs require 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. The Frequency of 31 days and 184 days, as applicable, considers instrument reliability, and operating experience has shown it proper for detecting degradation. In addition, the 184 day frequency of SR 3.4.7.4 is supported by the 31 day source check requirement of SR 3.4.7.3.

SR 3.4.7.3

This SR requires performance of a source check of the required drywell atmospheric monitoring system. The source check is a qualitative assessment of the radiation detector response when the radiation detector is exposed to a source of increased radioactivity. This will ensure that the radiation detector can detect a significant increase in radioactivity levels in the drywell atmosphere. The Frequency of 31 days considers detector reliability, and operating experience has shown it proper for detecting degradation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.5

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. USAR, Section 5.2.5.1.1.
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 Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. USAR, Section 5.2.5.5.3.
7. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure, in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the USAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The limit on specific activity is a value from a parametric evaluation of typical site locations. This limit is conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site. RCS specific activity satisfies Criterion 2 of Reference 3.
LCO	The specific iodine activity is limited to ≤ 0.2 μCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits.
APPLICABILITY	In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment. In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.
ACTIONS	<u>A.1 and A.2</u> When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems. A Note to the Required Action of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to $\leq$ 0.2 μCi/gm within 48 hours, or if at any time it is > 4.0 μCi/gm, it must be determined at least every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100 during a postulated MSLB accident.

Alternately, the plant can be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for bringing the plant to MODES 3 and 4 are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 100.11.
2. USAR, Section 15.6.4.
3. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to ≤ 200°F in preparation for performing Refueling or Cold Shutdown maintenance operations, or the decay heat must be removed for maintaining the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Service Water System (LCO 3.7.1, "Service Water (SW) System and Ultimate Heat Sink (UHS)").

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result.

The RHR Shutdown Cooling System meets Criterion 4 of Reference 1.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of

(continued)

BASES

LCO (continued)

one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR cut-in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR Shutdown Cooling System must be OPERABLE and one RHR shutdown cooling subsystem shall be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut-in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut-in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

(continued)

BASES (continued)

ACTIONS

A Note to the ACTIONS excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the redundancy of the OPERABLE subsystems, the low pressure at which the plant is operating, the low probability of an event occurring during operation in this condition, and the availability of alternate methods of decay heat removal capability.

A second Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies 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 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 shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

<u>A.1, A.2, and A.3</u>

With one RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam Systems, the Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate/Feed System), and a combination of an ECCS pump and S/RVs.

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant at ≤ 200°F in preparation for performing Refueling maintenance operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Service Water (SW) System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result.

The RHR Shutdown Cooling System meets Criterion 4 of Reference 1.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the heat exchanger and the RHR pump seal cooler, and the associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide

(continued)

BASES

LCO (continued)

redundancy. Operation of one subsystem can maintain and reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 4, the RHR Shutdown Cooling System must be OPERABLE and one RHR shutdown cooling subsystem shall be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 200°F. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut-in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut-in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the cut-in permissive pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies 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 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 shutdown cooling subsystems provided appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1

With one of the two RHR shutdown cooling subsystems inoperable except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam Systems, the Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate/Feed System), and a combination of an ECCS pump and S/RVs.

(continued)

BASES

ACTIONS (continued)	<u>B.1 and B.2</u> With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability. During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling system or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.
SURVEILLANCE REQUIREMENTS	<u>SR 3.4.10.1</u> This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.
REFERENCES	1. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Specification contains P/T limit curves for heatup, cooldown, system leakage and hydrostatic testing, and criticality, and also limits the maximum rate of change of reactor coolant temperature. The P/T limit curves are applicable up to 12.8 effective full power years.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

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

(continued)

BASES

BACKGROUND (continued)

as necessary, based on the evaluation findings and the recommendations of Reference 5.

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

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

The P/T criticality limits include the Reference 1 requirement that they be at least 40°F above the non-critical heatup curve or the non-critical cooldown curve and not lower than the minimum permissible temperature for the system leakage and hydrostatic testing. Reference 1 also allows boiling water reactors to operate with the core critical below the minimum permissible temperature allowed for the inservice hydrostatic pressure test (i.e., system leakage and hydrostatic testing) when the water level is within the normal range for power operation and the pressure is less than 20% of the preservice system hydrostatic test pressure (for NMP2, this pressure is 312 psig). Under these conditions, the minimum temperature is 60°F above the RT_{NDT} of the closure flange regions which are stressed by the bolt preload (for NMP2, this temperature is 70°F). This P/T region is delineated on the P/T curves (Figures 3.4.11-4 and 3.4.11-5) using cross-hatching.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. References 7 and 8 approved the curves and limits required by this Specification. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of Reference 9.

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in Figures 3.4.11-1, 3.4.11-2, 3.4.11-3, 3.4.11-4, and 3.4.11-5, heatup and cooldown rates are ≤ 100°F in any 1 hour period during RCS heatup, cooldown, and system leakage and hydrostatic testing, and the RCS temperature change during system leakage and hydrostatic testing is ≤ 20°F in any 1 hour period when the RCS temperature and pressure are not within the limits of Figure 3.4.11-2 or Figure 3.4.11-3, as applicable;

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ≤ 145°F during recirculation pump startup, and during increases in THERMAL POWER or jet pump loop flow while in single loop operation at low THERMAL POWER or jet pump loop flow;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is ≤ 50°F during recirculation pump startup, and during increases in THERMAL POWER or jet pump loop flow while in single loop operation at low THERMAL POWER or jet pump loop flow;

d. RCS pressure and temperature are within the criticality limits specified in Figures 3.4.11-4 and 3.4.11-5, prior to achieving criticality; and

(continued)

BASES

LCO (continued)

e. The reactor vessel flange and the head flange temperatures are ≥ 70°F when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits controls the thermal gradient through the vessel wall and is used as input for calculating the heatup, cooldown, and system leakage and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

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

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

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be brought to a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Pressure and temperature are reduced by bringing the plant 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.

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

Condition C is modified by a Note requiring Required Action C.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1 (continued)

increments, 30 minutes permits assessment and correction of minor deviations. The limits of Figures 3.4.11-1, 3.4.11-2, 3.4.11-3, 3.4.11-4, and 3.4.11-5 are met when operation is to the right of the applicable limit curve. For Figures 3.4.11-4 and 3.4.11-5, the cross-hatched portion of the curve is only applicable when reactor water level is in the normal, power operation range (178.3 inches to 187.3 inches, narrow range indication).

Surveillance for heatup, cooldown, or system leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

This SR has been modified by a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and system leakage and hydrostatic testing.

SR 3.4.11.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical. The limits of Figures 3.4.11-4 and 3.4.11-5 are met when operation is to the right of the applicable limit curve. The cross-hatched portion of the curve is only applicable when reactor water level is in the normal, power operation range (178.3 inches to 187.3 inches, narrow range indication).

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.11.3 and SR 3.4.11.4

Differential temperatures within the applicable limits ensure that thermal stresses resulting from the startup of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.3 and SR 3.4.11.4 (continued)

an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 10) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.11.3 and SR 3.4.11.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during a recirculation pump startup since this is when the stresses occur. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

SR 3.4.11.5 and SR 3.4.11.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increase in THERMAL POWER or jet pump loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels > 30% of RTP and with single loop jet pump flow

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.5 and SR 3.4.11.6 (continued)

rate > 50% of rated jet pump loop flow. Therefore, SR 3.4.11.5 and SR 3.4.11.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.11.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop cannot be introduced into the remainder of the Reactor Coolant System.

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits within 30 minutes before and every 30 minutes thereafter while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 80°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 90°F, monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the specified limits.

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.11.7 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.11.8 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 80°F in MODE 4. SR 3.4.11.9 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature ≤ 90°F in MODE 4.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.7, SR 3.4.11.8, and SR 3.4.11.9 (continued)

The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. Letter from S.A. Varga (NRC) to C.V. Mangan (NMPC), "Issuance of Facility Operating License No. NPF-69 - Nine Mile Point Nuclear Station, Unit 2," dated July 2, 1987.
8. Letter from D.S. Brinkman to B.R. Sylvia (NMPC), "Issuance of Amendment 26 for Nine Mile Point Nuclear Station, Unit 2," dated January 11, 1991.
9. 10 CFR 50.36(c)(2)(ii).
10. USAR, Section 15.4.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of Design Basis Accidents (DBAs) and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1035 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. References 2 and 3 also assume an initial reactor steam dome pressure for the analyses of DBAs and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and fuel design limits (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). While the transient analyses for determining the Operating Limit MCPR assume a nominal initial reactor steam dome pressure (i.e., less than 1035 psig), analyses at representative pressures around the nominal operating pressure would not produce any significant change in MCPR. Also, the resulting peak reactor pressure is always bounded by the vessel overpressure protection analysis. Reactor steam dome pressure satisfies the requirements of Criterion 2 of Reference 4.
LCO	The specified reactor steam dome pressure limit of ≤ 1035 psig ensures the plant is operated within the assumptions of the reactor overpressure analysis. Operation above the limit may result in a response more severe than analyzed.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam, and events that may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1

Verification that reactor steam dome pressure is ≤ 1035 psig ensures that the initial conditions of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

(continued)

BASES (continued)

REFERENCES	1.	USAR, Section 5.2.2.2.2 and A.5.2.2.2.2.
	2.	USAR, Chapter 15 and Appendix A.
	3.	USAR, Section 6.3.3.2.
	4.	10 CFR 50.36(c)(2)(ii).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.1 ECCS—Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. The ECCS also consists of the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tank (CST), it is capable of providing a source of water for the HPCS System.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously the system aligns, and the pumps inject water, taken either from the CST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCS pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the spray sparger above the core. If the break is small, HPCS will maintain coolant inventory, as well as vessel level, while the RCS is still pressurized. If HPCS fails, it is backed up by ADS in combination with LPCI and LPCS. In this event, the ADS timed sequence would be allowed to time out and open the selected safety/relief valves (S/RVs), depressurizing the RCS and allowing the LPCI and LPCS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly, and the LPCI and LPCS systems cool the core.

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the Service Water (SW) System. Depending on the location and size of

(continued)

BASES

BACKGROUND (continued)

the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break.

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS subsystems.

The LPCS System (Ref. 1) consists of a motor driven pump, a spray sparger above the core, piping, and valves to transfer water from the suppression pool to the sparger. The LPCS System is designed to provide cooling to the reactor core when the reactor pressure is low. Upon receipt of an initiation signal, the LPCS pump is automatically started in approximately 10 seconds if normal AC power is available and in approximately 6 seconds after emergency AC power is available. When the RPV pressure drops sufficiently, LPCS flow to the RPV begins. A full flow test line is provided to route water to the suppression pool to allow testing of the LPCS System without spraying water into the RPV.

LPCI is an independent operating mode of the RHR System. There are three LPCI subsystems. Each LPCI subsystem (Ref. 2) consists of a motor driven pump, piping, and valves to transfer water from the suppression pool to the core. Each LPCI subsystem has its own suction and discharge piping and separate vessel nozzle that connects with the core shroud through internal piping. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, each LPCI pump is automatically started (C pump in approximately 10 seconds if normal AC power is available and in approximately 6 seconds after emergency AC power is available; A and B pumps in approximately 5 seconds if normal AC power is available and in approximately 1 second after emergency AC power is available). When the RPV pressure drops sufficiently, LPCI flow to the RPV begins. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the core. A full flow test line is provided to route water to the suppression pool to allow testing of each LPCI pump without injecting water into the RPV.

The HPCS System (Ref. 3) consists of a single motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suction source to the sparger.

(continued)

BASES

BACKGROUND (continued)

Suction piping is provided from the CST (CST B) and the suppression pool. Pump suction is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCS System. The HPCS System is designed to provide core cooling over a wide range of RPV pressures (0 psid to 1200 psid, vessel to suction source). Upon receipt of an initiation signal, the HPCS pump automatically starts (when AC power is available) and valves in the flow path begin to open. Since the HPCS System is designed to operate over the full range of expected RPV pressures, HPCS flow begins as soon as the necessary valves are open. Full flow test lines are provided to route water to the CST and to the suppression pool to allow testing of the HPCS System during normal operation without spraying water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed or RPV pressure is greater than the LPCS or LPCI pump discharge pressures following system initiation. In addition, the LPCS and LPCI minimum flow valves are normally open when the associated system is in the standby condition. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the ECCS discharge line "keep fill" systems are designed to maintain all pump discharge lines filled with water.

The ADS (Ref. 4) consists of 7 of the 18 S/RVs. It is designed to provide depressurization of the primary system during a small break LOCA if HPCS fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems, so that these subsystems can provide core cooling. Each ADS valve is supplied with pneumatic power from a nitrogen supply system, which includes nitrogen accumulators for each ADS valve located in the drywell. Each ADS accumulator will provide sufficient nitrogen pressure to maintain the respective ADS valve open for at least 13.8 hours. In addition, during post LOCA conditions, the ADS accumulators can be recharged by one of two ADS nitrogen receiver tanks. The supply from the receiver tanks is sufficient for 5 days under post LOCA

(continued)

BASES

BACKGROUND (continued)

conditions. If additional nitrogen is required, the receiver tanks can be recharged by either a non-safety bank of six nitrogen tanks located outside of the reactor building or if unavailable by the special emergency recharging lines. The recharge capability guarantees a 100 day supply of nitrogen for the ADS function during a post LOCA condition. The ADS function is utilized post LOCA to ensure the reactor pressure is maintained below the shutoff head of the low pressure ECCS pumps and to provide a flow path for alternate shutdown cooling.

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 8), and the results of these analyses are described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a large break LOCA, failure of ECCS subsystems in Division 1 (LPCS and LPCI-A) or Division 2 (LPCI-B and LPCI-C) due to failure of its associated diesel generator is, in general, the most severe failure. For a small break LOCA, HPCS System failure is the most severe failure. The small break analysis also assumes 2 ADS valves are

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

inoperable at the time of the accident. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of Reference 12.

LCO

Each ECCS injection/spray subsystem and six ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS injection/spray subsystems are defined as the LPCS System and the three LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, the ADS function is not required when pressure is ≤ 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS—Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 13) that evaluated the impact on ECCS availability by assuming that various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

If the HPCS System is inoperable, and the RCIC System is immediately verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other information, to determine if RCIC is out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be immediately verified and RCIC is required to be OPERABLE, Condition D must be entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on the results of a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 13.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

E.1

The LCO requires six ADS valves to be OPERABLE to provide the ADS function. Reference 14 contains the results of an analysis that evaluated the effect of two of seven ADS valves being out of service. This analysis showed that assuming a failure of the HPCS System, operation of only five ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one required ADS valve inoperable, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure (ADS) and low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 13) and has been found to be acceptable through operating experience.

G.1 and G.2

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more required ADS valves are inoperable, the plant must be brought to a condition 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 reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a condition outside of the design basis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The 31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

In MODE 3 with reactor steam dome pressure less than the actual RHR cut-in permissive pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than the RHR cut-in permissive pressure, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

SR 3.5.1.3

Verification every 31 days that ADS nitrogen receiver discharge header pressure is ≥ 160 psig and ADS nitrogen receiver tank pressure is ≥ 334 psig assures adequate nitrogen pressure for reliable ADS operation. The accumulator on each ADS valve provides nitrogen pressure for valve actuation. The designed nitrogen supply pressure requirements for the accumulator are such that, following a failure of the nitrogen supply to the accumulator, at least one valve actuation can occur with the drywell at 100% of design pressure (Ref. 15). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation cf the low pressure ECCS. This minimum required nitrogen receiver discharge header pressure of 160 psig is provided by two ADS nitrogen receiver tanks. The minimum ADS nitrogen receiver tank pressure of 334 psig ensures a 5 day supply of nitrogen is available to recharge the ADS accumulators. The 31 day Frequency takes into consideration administrative control over operation of the nitrogen receiver tanks and alarms for low nitrogen pressure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The performance requirements of the ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system head that is equivalent to the RPV pressure expected during a LOCA. The total developed head is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, i.e., actuation of the system throughout its emergency operating sequence, which includes automatic pump startup and actuation of all automatic valves (including the LPCI flow diversion valves closed on a Reactor Vessel Water Level—Low, Level 3 or a Drywell Pressure—High (Boundary Isolation) signal) to their required positions. This Surveillance also ensures that the HPCS System will automatically restart (i.e., injection valve re-open) on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) signal and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.6

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.7

A manual actuation of each ADS actuator is performed to verify that the valve and solenoids are functioning properly. This can be demonstrated by one of two methods. Each ADS actuator can be tested using either method. The first method is a manual actuation of the ADS valve with verification of the response of the turbine control or bypass valves, by a change in the measured steam flow, or by any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitor). Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed, after the required pressure and flow are achieved, to perform this test. Adequate pressure at which this test is to be performed is 950 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by at least 2 turbine bypass valves open. Reactor startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR.

The second method involves cycling the actuator of the ADS valves prior to startup of the unit. A sample population of S/RVs are normally removed and bench tested as required by SR 3.4.4.1. Since the ADS valves are also S/RVs, bench testing the S/RVs also cycles the ADS valves. The successful performance of the bench test for this sample provides a reasonable assurance that the remaining ADS valves that were not bench tested in this sample will perform (i.e., open when required) in a similar fashion. After each ADS valve is reinstalled following a bench test, the actuator of the ADS valve shall be uncoupled from the ADS valve stem and cycled using one solenoid to ensure that no damage has occurred to the ADS valve actuator during transportation and installation and to ensure one solenoid is functioning properly. In addition, the ADS valves not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

removed and bench tested shall be tested in a similar manner to verify one solenoid and the actuator. Uncoupling from the ADS valve stem allows operation of the actuator without disturbing the valve disc seat interface and thereby minimizes the likelihood of steam leaking past the ADS valve seat when it is closed. If performed using this method, ADS valve OPERABILITY has been demonstrated while shutdown for each ADS valve based upon the successful bench testing of a sample population of S/RVs and the successful operation of the actuator and a solenoid for the remaining ADS valves. Thus the Note that modifies this SR is not needed since reactor steam pressure is not used to lift the valve.

SR 3.5.1.6 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency of 24 months on a STAGGERED TEST BASIS ensures that both solenoids for each ADS valve are alternately tested. The Frequency is based on the need to perform this Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is less than or equal to the maximum value assumed in the accident analysis. Response time testing acceptance criteria are included in Reference 16. This SR is modified by a Note that allows the instrumentation portion of the response time to be assumed to be the design instrumentation response time and therefore, is excluded from the ECCS RESPONSE TIME testing. This is allowed since the instrumentation response time is a small part of the ECCS RESPONSE TIME (e.g., sufficient margin exists in the diesel generator start time when compared to the instrumentation response time) (Ref. 17).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.8 (continued)

ECCS RESPONSE TIME tests are conducted every 24 months. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience.

REFERENCES

1. USAR, Section 6.3.2.2.3.
2. USAR, Section 6.3.2.2.4.
3. USAR, Section 6.3.2.2.1.
4. USAR, Section 6.3.2.2.2.
5. USAR, Section 15.6.6.
6. USAR, Section 15.6.4.
7. USAR, Section 15.6.5.
8. 10 CFR 50, Appendix K.
9. USAR, Section 6.3.3.
10. 10 CFR 50.46.
11. USAR, Section 6.3.3.3.
12. 10 CFR 50.36(c)(2)(ii).
13. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
14. USAR, Chapter 15C.
15. USAR, Section 5.2.2.4.1.
16. Technical Requirements Manual.
17. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 ECCS—Shutdown

BASES

BACKGROUND

A description of the High Pressure Core Spray (HPCS) System, Low Pressure Core Spray (LPCS) System, and low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgment, that while in MODES 4 and 5, one ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.

The ECCS satisfy Criterion 3 of Reference 2.

LCO

Two ECCS injection/spray subsystems are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank B (CST) to the RPV. The necessary portions of the Service Water System and Ultimate Heat Sink capable of providing cooling to the RHR pump seal cooler are also required for a LPCI subsystem.

One LPCI subsystem (A or B) may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and

(continued)

BASES

LCO (continued)

operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery.

APPLICABILITY

OPERABILITY of the ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 22 ft 3 inches above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is < 150 psig, and the LPCS, HPCS, and LPCI subsystems can provide core cooling without any depressurization of the primary system.

ACTIONS

A.1 and B.1

If any one required ECCS injection/spray subsystem is inoperable, the required inoperable ECCS injection/spray subsystem must be restored to OPERABLE status within 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient RPV flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the availability of one subsystem and the low probability of a vessel draindown event.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

C.1, C.2, D.1, D.2, and D.3

If both of the required ECCS injection/spray subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must be initiated immediately to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours. The 4 hour Completion Time to restore at least one ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

If at least one ECCS injection/spray subsystem is not restored to OPERABLE status within the 4 hour Completion Time, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isclation capability is available in each secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. The administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated). This may be performed by an administrative check, by examining logs or other

(continued)

BASES

ACTIONS

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

information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of 195 ft required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST.

When the suppression pool level is < 195 ft, the HPCS System is considered OPERABLE only if it can take suction from CST B and CST B water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is ≥ 195 ft or the HPCS System is aligned to take suction from the CST and the CST contains ≥ 253,000 gallons of water, equivalent to 26.9 ft, ensures that the HPCS System can supply 135,000 gallons of makeup water to the RPV. In addition, to ensure the 135,000 gallons of makeup water is available, the HPCS suction source auto-swap from the CST to the suppression pool must be disabled (e.g., by closing the suppression pool suction valve and deenergizing the breaker for the valve motor operator). This is necessary since the actual trip setpoint of the HPCS Pump Suction Pressure—Low Function is at a pressure sufficiently high such that 135,000 gallons would not be available before the auto-swap occurred.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2 (continued)

applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.8 are applicable to SR 3.5.2.3, SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7, respectively.

SR 3.5.2.4

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

In MODES 4 and 5, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows one LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.5.2.4 (continued) Because of the low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.
REFERENCES	1. USAR, Section 6.3.3.3. 2. 10 CFR 50.36(c)(2)(ii).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the head spray nozzle. Suction piping is provided from the condensate storage tank A (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from main steam line B, upstream of the inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, 165 psia to 1215 psia. Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)	The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge line "keep fill" system is designed to maintain the pump discharge line filled with water.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, the system satisfies Criterion 4 of Reference 3.
LCO	The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.
APPLICABILITY	The RCIC System is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.
ACTIONS	<u>A.1 and A.2</u> If the RCIC System is inoperable during MODE 1, or MODES 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCS System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

In this condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high RPV pressure since the HPCS System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of the HPCS is therefore immediately verified when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if the HPCS is out of service for maintenance or other reasons. Verification does not require performing the Surveillances needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of the HPCS System cannot be immediately verified, however, Condition B must be entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCS) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 4) that evaluated the impact on ECCS availability, assuming that various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of the similar functions of the HPCS and RCIC, the AOTs (i.e., Completion Times) determined for the HPCS are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCS System is simultaneously inoperable, the plant must be brought to a condition 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 reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high point. The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves (including the RCIC pump flow controller) in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested both at the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Adequate reactor steam pressure to perform SR 3.5.3.3 is 935 psig and to perform SR 3.5.3.4 is 150 psig. Adequate steam flow is represented by at least one turbine bypass valve open. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for the flow tests after the required pressure and flow are reached are sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SRs.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply during startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause the system to operate as designed, i.e., actuation of the system throughout its emergency operating sequence, which includes automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool on a CST low water level signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

While this surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
2. USAR, Section 5.4.6.1.
3. 10 CFR 50.36(c)(2)(ii).
4. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

    1. capable of being closed by an OPERABLE automatic containment isolation system, or

    2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";

c. All equipment hatches are closed and sealed; and

d. The sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, or O-rings) is OPERABLE (i.e., OPERABLE such that the primary containment leakage limits are met).

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BASES

BACKGROUND (continued)

This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 1.1% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 39.75 psig (Ref. 4).

Primary containment satisfies Criterion 3 of Reference 5.

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq$ 1.0 L_a, except prior to the first startup after performing a required 10 CFR 50 Appendix J Testing Program Plan leakage test. At this time, the applicable leakage limits must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the primary containment pressure does not exceed design limits. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those

(continued)

BASES

LCO (continued)	leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.
ACTIONS	<u>A.1</u> In the event that primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal. <u>B.1 and B.2</u> If primary containment cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.1.1</u> Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of 10 CFR 50 Appendix J Testing Program Plan. Failure to meet air lock leakage limit (SR 3.6.1.2.1), secondary containment bypass leakage limit

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

(SR 3.6.1.3.11), resilient seal primary containment purge valve leakage limit (SR 3.6.1.3.6), or main steam isolation valve leakage limit (SR 3.6.1.3.12) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of 10 CFR 50 Appendix J Testing Program Plan.

As left leakage prior to the first startup after performing a required 10 CFR 50 Appendix J Testing Program Plan leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

SR 3.6.1.1.2 and SR 3.6.1.1.3

Maintaining the pressure suppression function of the primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. SR 3.6.1.1.2 measures drywell-to-suppression chamber differential pressure to ensure that the leakage paths that would bypass the suppression pool are within allowable limits. The suppression chamber-to-drywell vacuum breakers are the most likely source of potential bypass leakage, therefore, these valves are normally tested on a more frequent basis.

Satisfactory performance of SR 3.6.1.1.2 can be achieved by establishing a known differential pressure (≥ 3.0 psid) between the drywell and the suppression chamber and verifying that the $A/\sqrt{K}$ calculated from the measured bypass leakage is equivalent to that through an area ≤ 0.0054 ft^2. The leakage test is performed at the same Frequency as the Type A testing requirements of the 10 CFR 50 Appendix J Testing Program Plan. This Frequency was developed since historically the leakage is much less than the design value and that the most credible source of potential bypass

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 and SR 3.6.1.1.3 (continued)

leakage, the suppression chamber-to-drywell vacuum breakers will normally be tested more frequently in accordance with SR 3.6.1.1.3. Two consecutive as-found test failures of SR 3.6.1.1.2, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 24 months is required until the situation is remediated as evidenced by passing two consecutive tests.

Conservative test criteria was chosen for SR 3.6.1.1.3 based on the assumed bypass leakage in the LOCA analysis. The 24 month Frequency specified for SR 3.6.1.1.3 was developed considering it is prudent that this Surveillance be performed during a unit outage. A Note has been added to SR 3.6.1.1.3 which provides an allowance not to perform SR 3.6.1.1.3 when SR 3.6.1.1.2 is required to be performed since SR 3.6.1.1.2 will provide adequate information on the capacity of the pressure suppression function of the primary containment.

REFERENCES

1. USAR, Section 6.2.
2. USAR, Section 15.6.5.
3. 10 CFR 50, Appendix J, Option B.
4. USAR, Section 6.2.6.1.
5. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double-door primary containment air locks (equipment and personnel airlock and escape airlock) have been built into the primary containment to provide personnel access to the primary containment and to provide primary containment isolation during the process of personnel entry and exit. The air locks are designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors has a double-gasket compression seal and local leak testing capability to ensure pressure integrity. To effect a leak tight seal, the airlock design uses pressure sealed doors (i.e., an increase in primary containment internal pressure results in increased sealing on each door).

Each air lock is nominally a right circular cylinder, with doors at each end that are interlocked to prevent simultaneous opening. The dimensions of the airlock are described in Reference 1. The air locks are provided with limit switches on both doors in each air lock that provide local indication of door position. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions, as allowed by this LCO, the primary containment may be accessed through the air lock when the door interlock mechanism has failed, by manually performing the interlock function.

The primary containment air locks form part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a

(continued)

BASES

BACKGROUND (continued)	DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.1% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 39.75 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. Primary containment air locks satisfy Criterion 3 of Reference 3.
LCO	As part of the primary containment pressure boundary, the air lock safety function is related to control of containment leakage following a DBA. Thus, the air lock structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from primary containment.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit.

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by a third Note, which ensures appropriate remedial actions are taken when necessary, if air lock leakage results in exceeding overall containment leakage rate acceptance criteria. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment leakage

(continued)

BASES

ACTIONS (continued)

is exceeding L_a. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

A.1, A.2, and A.3

With one primary containment air lock door inoperable in one or more primary containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 ensures that the affected air lock penetration has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate given the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable.

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

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

With an air lock interlock mechanism inoperable in one or both primary containment air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in one air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

(continued)

BASES

ACTIONS

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

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected primary containment air locks must be verified closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours (Required Action C.3). The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in each affected air lock.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the 10 CFR 50 Appendix J Testing Program Plan. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established as a small fraction of the total allowable primary containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Types B and C primary containment leakage rate.

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.2 (continued)

containment pressure (Ref. 2), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the primary containment air lock door is used for entry and exist (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the air lock.

REFERENCES

1. USAR, Section 3.8.1.1.2.
2. USAR, Section 6.2.6.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs and the non-PCIVs listed in Table 3.6.1.3-1 (2CMS*SOV74A, 74B, 75A, 75B, 76A, 76B, 77A, and 77B), in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges (which include plugs and caps as listed in Reference 1), and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration, except for penetrations isolated by excess flow check valves, so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

The 12 and 14 inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions. The 12 and 14 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. However, the purge valves may be open when being used for pressure control, inerting, de-inerting, ALARA, or air quality considerations since they are fully qualified.

(continued)

BASES

BACKGROUND (continued)	A two inch bypass line is provided when the primary containment full flow line to the Standby Gas Treatment (SGT) System is isolated.

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV (and non-PCIVs listed in Table 3.6.1.3-1) OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a loss of coolant accident (LOCA) and a main steam line break (MSLB) (Refs. 2 and 3). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in References 2 and 3, the LOCA is the most limiting event due to radiological consequences. In addition, the non-PCIVs listed in Table 3.6.1.3-1 are also assumed to be closed during the LOCA. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 3 second closure time is assumed in the MSIV closure (the most severe overpressurization transient) analysis (Ref. 4) and 5 second closure time is assumed in the MSLB analysis (Ref. 3). Likewise, it is assumed that the primary containment isolates such that release of fission products to the environment is controlled.

The DBA analysis assumes that isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a, prior to fuel damage.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

PCIVs satisfy Criterion 3 of Reference 5.

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. The valves covered by this LCO are listed with their associated stroke times in Ref. 1.

The normally closed manual PCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. Normally closed automatic PCIVs, which are required by design (e.g., to meet 10 CFR 50 Appendix R requirements) to be de-activated and closed, are considered OPERABLE when the valve is closed and de-activated. These passive isolation valves and devices are those listed in Reference 1. Purge valves with resilient seals, secondary containment bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents. In addition, the LCO ensures leakage through the non-PCIVs listed in Table 3.6.1.3-1 are within the limits assumed in the accident analysis.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be normally closed in MODES 4 and 5. Certain valves are required to be OPERABLE, however, to prevent inadvertent reactor vessel draindown. These valves are

(continued)

BASES

APPLICABILITY (continued)

those whose associated instrumentation is required to be OPERABLE according to LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures 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 are not 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 secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period 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 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 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 the primary containment and capable of being mispositioned are in the correct position. The Completion Time for this verification 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 devices inside the primary containment the specified time period of "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 the existence of 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

Required Action A.2 is modified by two 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 or more PCIVs inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within 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 affected by a single active failure.

Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

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

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within 4 hours except for excess flow check valves (EFCVs) and penetrations with a closed system and 72 hours for EFCVs and penetrations with a closed system. The Completion Time of 4 hours for valves other than EFCVs and in penetrations with a closed system 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. The 72 hour Completion Time for penetrations with a closed system 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 closed system must meet the requirements of Ref. 6. The Completion Time of 72 hours for EFCVs is also reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This 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 that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two or more PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by two 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.

D.1, D.2, and D.3

With the secondary containment bypass leakage rate (SR 3.6.1.3.11), MSIV leakage rate (SR 3.6.1.3.12), or hydrostatically tested line leakage rate (SR 3.6.1.3.13) not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage rate must be restored to within limit or the affected penetration flow path must be isolated within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours. 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. Required

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Action D.1 is modified by a Note stating that the isolation device used to satisfy the Required Action must meet the same leakage rate requirements as the inoperable valve. Thus, when the 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 4 hour Completion Time for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function. The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "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 isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Required Action D.2 is modified by two 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.

For the containment purge supply valve with resilient seal that is closed in accordance with Required Action D.1, SR 3.6.1.3.6 must be performed at least once every 92 days, as required by D.3. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge supply valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

E.1, E.2, and E.3

In the event one or more containment purge exhaust valves are not within the purge valve leakage limits, purge exhaust valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. If a purge exhaust valve with resilient seals is utilized to satisfy Required Action E.1 it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. The specified Completion Time

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "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 isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Required Action E.2 is modified by two 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.

For the containment purge exhaust valve with resilient seal that is closed in accordance with Required Action E.1, SR 3.6.1.3.6 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

containment purge exhaust valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the plant 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. If suspending the OPDRVs 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 valves 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 verifies that the 12 inch and 14 inch primary containment purge valves are closed as required or, if open, opened for an allowable reason.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

The SR is modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided that either: a) the SGT System is OPERABLE (i.e., both subsystems); or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE. These primary containment purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The allowance is intended to balance the operational needs of the unit with the requirement to preclude a radiological release through the purge exhaust lines. With the primary containment atmosphere being exhausted through the containment full flow line to the SGT System, a pressure transient could damage the operating SGT subsystem. Thus both subsystems are required to be OPERABLE when the full flow line is in service. This ensures that, if an accident occurs that damages the operating SGT subsystem, the remaining SGT subsystem is still available to perform the intended SGT System safety function. When the full flow line is not in service (i.e., the two inch bypass valve is open), then only one SGT subsystem is required to be OPERABLE since a pressure transient cannot damage the operating SGT subsystem. The 31 day Frequency is consistent with other primary containment isolation valve requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for PCIVs outside primary containment is relatively easy, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.2 (continued)

31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency of "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 appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that each valve will isolate in a time period less than or equal to that assumed in the safety analysis. The Frequency of this SR is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J Option B (Ref. 7), is required to ensure OPERABILITY. The primary containment purge supply valves, which are secondary containment bypass leakage pathway valves, are tested at a pressure of 40.0 psig and the primary containment purge exhaust valves, which are not secondary containment bypass leakage pathway valves, are tested at P_a, 39.75 psig. The leakage limit for the 12 inch supply and exhaust valves are 3.75 scfh while the 14 inch supply and exhaust valve leakage limit is 4.38 scfh. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining these penetrations leak tight (due to the direct path between primary containment and the environment in some cases), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.8

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.8 (continued)

Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. In addition, this Surveillance shall be performed in MODE 4 or 5.

SR 3.6.1.3.9

This SR requires a demonstration that each EFCV is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This SR provides assurance that the instrumentation line EFCVs will perform as designed. Some hydraulic EFCVs are tested by providing an instrument line break signal with reactor pressure above 600 psig. Testing above this pressure range provides a high degree of assurance that these valves will close during an instrument line break while at normal operating pressure. The remaining hydraulic EFCVs are tested with process fluid or demin water at low pressure. The pneumatic EFCVs are tested by providing an instrument line break signal with pressure at approximately 15 psig to 150 psig. These test pressures are selected to simulate the actual operating conditions the EFCVs are expected to experience during instrument line breaks outside containment.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired, and shall be installed in accordance with the manufacturer's recommendations. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths (with the exception of the MSIVs, which are tested per SR 3.6.1.3.12) is less than or equal to the specified leakage rate. While the MSIVs are also classified as secondary containment bypass leakage pathway valves, they are evaluated according to SR 3.6.1.3.12, and if not within limits, actions are required to be taken in accordance with ACTION D. This provides assurance that the assumptions in the radiological evaluations that form the basis of the USAR (Ref. 2) are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

Bypass leakage is considered part of L_a.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.12

The analyses in Reference 1 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 24 scfh when tested at 40 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

MSIV leakage is considered part of L_a.

SR 3.6.1.3.13

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 1 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 1 gpm times the total number of hydrostatically tested PCIVs when tested at ≥ 1.10 P_a (43.73 psig). The combined leakage rates must be demonstrated in accordance with the leakage test Frequency required by the 10 CFR 50 Appendix J Testing Program Plan.

REFERENCES

1. Technical Requirements Manual.
2. USAR, Section 15.6.5.
3. USAR, Section 15.6.4.
4. USAR, Section 15.2.4.
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section 6.2.4.3.2.
7. 10 CFR 50, Appendix J Option B.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell and Suppression Chamber Pressure

BASES

BACKGROUND

The drywell and suppression chamber internal pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

Transient events, which include inadvertent drywell spray initiation, can reduce the drywell and suppression chamber internal pressure. Without an appropriate limit on the minimum drywell and suppression chamber internal pressure (14.2 psia), the design limit for negative containment differential pressure of 4.7 psid could be exceeded (Ref. 1).

The limitation on the maximum drywell and suppression chamber internal pressure (15.45 psia) provides added assurance that the peak LOCA drywell and suppression chamber pressure does not exceed the design value of 45 psig (Ref. 1).

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 2). Among the inputs to the design basis analysis is the initial drywell and suppression chamber internal pressure. The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 45 psig and that peak negative pressure for an inadvertent drywell spray event does not exceed the design value of 4.7 psid.

Drywell and suppression chamber pressure satisfies Criterion 2 of Reference 3.

LCO

A limitation on the drywell and suppression chamber internal pressure of ≥ 14.2 psia and ≤ 15.45 psia is required to ensure that primary containment initial conditions are consistent with the initial safety analyses assumptions so that containment pressures remain within design values during a LOCA and the design value of containment negative pressure is not exceeded during an inadvertent operation of drywell sprays.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, a DBA could result in a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell and suppression chamber internal pressure within limits is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> When drywell or suppression chamber internal pressure is not within the limits of the LCO, drywell and suppression chamber internal pressure must be restored to within limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour. <u>B.1 and B.2</u> If drywell and suppression chamber internal pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.4.1</u> Verifying that drywell and suppression chamber internal pressure is within limits ensures that operation remains within the limits assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending primary containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal primary containment pressure condition.

(continued)

BASES (continued)

REFERENCES	1.	USAR, Section 6.2.1.1.3.
	2.	USAR Section 6.2.
	3.	10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND

Heat loads from the drywell, as well as piping and equipment, add energy to the airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This drywell air temperature limit is an initial condition input for the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Analyses assume an initial average drywell air temperature of 150°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 340°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident.

In addition, the drywell average air temperature is the limiting initial condition used to determine the maximum negative differential pressure across the primary containment boundary following an inadvertent drywell spray actuation (Ref. 1).

Drywell air temperature satisfies Criterion 2 of Reference 2.

LCO

With an initial drywell average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the drywell design temperature and the design negative differential pressure

(continued)

BASES

LCO (continued)	across the primary containment boundary is not exceeded. As a result, the ability of primary containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> When drywell average air temperature is not within the limit of the LCO, it must be restored within 8 hours. This Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems. <u>B.1 and B.2</u> If the drywell average air temperature cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.5.1</u> Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. In order to determine the drywell average air temperature, an arithmetic average is calculated, using measurements taken at locations within the drywell selected to provide a representative sample of the overall drywell atmosphere.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1 (continued)

The required locations are approximately as follows, in elevation and azimuth: 244 ft 0 inches, 110°; 244 ft 0 inches, 284°; 253 ft 11 inches, 169°; 255 ft 6 inches, 326°; 262 ft 3 inches, 28°; 268 ft 0 inches, 203°; 282 ft 6 inches, 243°; 283 ft 0 inches, 58°; 294 ft 5 inches, 117°; 296 ft 4 inches, 323°; 306 ft 9 inches, 189°; and 306 ft 9 inches, 354°.

The 24 hour Frequency of this SR was developed based on operating experience related to drywell average air temperature variations and temperature dependent drift of instrumentation located in the drywell 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 primary containment air temperature condition.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Residual Heat Removal (RHR) Drywell Spray

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the suppression pool airspace, bypassing the suppression pool. The RHR Drywell Spray System is designed to mitigate the effects of bypass leakage. In addition, credit is taken for the turbulence induced by the sprays to ensure a well-mixed primary containment atmosphere during post-LOCA, which reduces the potential for a nonuniform hydrogen and oxygen concentration within the primary containment.

There are two redundant, 100% capacity RHR drywell spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, and one spray sparger inside the drywell. Dispersion of the spray water is accomplished by spray nozzles in each subsystem.

The RHR drywell spray mode will be manually initiated, if required, following a LOCA, according to emergency procedures.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 0.054 ft^2. The analysis demonstrates that with drywell spray operation (in conjunction with RHR suppression pool spray operation) the primary containment

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	pressure remains within design limits. The RHR drywell spray mode also helps promote a uniform mixing of hydrogen and oxygen in the containment following a LOCA (Ref. 2). The RHR drywell spray satisfies Criterion 3 of Reference 3.
LCO	In the event of a Design Basis Accident (DBA), a minimum of one RHR drywell spray subsystem is required to mitigate potential bypass leakage paths, maintain the primary containment peak pressure below design limits, and ensures adequate mixing of the containment atmosphere. To ensure that these requirements are met, two RHR drywell spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR drywell spray subsystem is OPERABLE when the pump and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR drywell spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR drywell spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR drywell spray subsystem is adequate to perform the primary containment bypass leakage mitigation and mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass leakage mitigation and mixing capability. The 7 day Completion Time was chosen in light of the redundant RHR drywell spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR drywell spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce primary containment pressure and ensure adequate mixing in the primary containment are available.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Verifying the correct alignment for manual and power operated valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR drywell spray mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.1.6.2

Verifying, by administrative means, that each required RHR pump is OPERABLE ensures that the RHR pump is capable of performing its intended function (i.e., capable of developing the assumed drywell spray flow rate) when in the drywell spray mode. This Surveillance is met by verifying that another required Surveillance, which demonstrated the RHR pump OPERABILITY, was performed within the required Frequency. The verification can be performed by examining logs or other information, to determine if a required RHR pump is out of service for maintenance or other reasons. It is not necessary to perform an additional Surveillance needed to demonstrate the OPERABILITY of the required RHR pumps. The Frequency of 92 days is consistent with the normal RHR pump flow rate Surveillance Frequency ("in accordance with the Inservice Testing Program") in other Surveillances.

SR 3.6.1.6.3

This Surveillance is performed every 10 years to verify by performance of an air flow test that the spray nozzles in the drywell spray spargers are not obstructed and that flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Section 6.2.5.2.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 8 vacuum breakers mounted in piping (two in series vacuum breakers per line) that connects the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark II Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is

(continued)

BASES

BACKGROUND (continued)	less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The vacuum breakers limit the height of the waterleg in the vent system during normal operation.
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Suppression chamber-to-drywell vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell floor. The safety analyses assume that the vacuum breakers are closed initially and start to open at a differential pressure of 0.25 psid (Ref. 1). Both vacuum breakers in three of the four vacuum breaker lines must open to satisfy the design basis. The additional vacuum breaker line is provided to accommodate the postulated single failure of one vacuum breaker in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that eight vacuum breakers be OPERABLE are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight until the suppression pool is at a positive pressure relative to the drywell. The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of Reference 2.
LCO	All vacuum breakers must be OPERABLE to provide assurance that the vacuum breakers will open so that drywell-to-suppression chamber negative differential pressure remains below the design value. This LCO also ensures that all suppression chamber-to-drywell vacuum breakers are closed (except during testing or when the vacuum breakers are

(continued)

BASES

LCO (continued)

performing their intended design function). The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell floor, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of drywell sprays.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one line with one or more vacuum breakers inoperable for opening (e.g., a vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining OPERABLE vacuum breakers in the other three lines are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers in the other three lines could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one or more of the vacuum breakers inoperable in one line, 72 hours is allowed to restore the inoperable vacuum breaker(s) to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more lines with one vacuum breaker not closed, communication between the drywell and suppression chamber airspace could occur, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. 72 hours is allowed to close the vacuum breaker due to the redundant capability afforded by the other vacuum breaker in the same line, (the fact that the other vacuum breaker is closed), and the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. As Noted, separate Condition entry is allowed for each vacuum breaker line.

C.1

With one or more lines with two vacuum breakers not closed, this allows communication between the drywell and suppression chamber, and as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, one open vacuum breaker must be closed. A short time is allowed to close one of the vacuum breakers due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test. As Noted, separate Condition entry is allowed for each vacuum breaker line.

D.1 and D.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of ≥ 0.25 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. This first Note allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers, open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The 31 day Frequency of this SR was developed, based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. A 31 day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.2 (continued)

since they are located in a harsh environment (the suppression chamber airspace). In addition, this functional test is required within 12 hours after a discharge of steam to the suppression chamber from the safety/relief valves.

SR 3.6.1.7.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker opening (i.e., starts to open from the fully closed position) differential pressure of ≤ 0.25 psid is valid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. USAR, Section 6.2.1.
2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The primary containment utilizes a Mark II over/under pressure suppression configuration, with the suppression pool located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design value (45 psig). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation (CO) loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the suppression pool temperature analyses required by Reference 3). An initial pool temperature of 90°F is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	temperature of 120°F are assumed for the Reference 2 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing. Suppression pool average temperature satisfies Criteria 2 and 3 of Reference 4.
LCO	A limitation on the suppression pool average temperature is required to assure that the primary containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows: a. Average temperature ≤ 90°F with THERMAL POWER > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met. b. Average temperature ≤ 105°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 90°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 90°F is short enough not to cause a significant increase in plant risk. c. Average temperature ≤ 110°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the plant will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down. At 1% RTP, heat input is approximately equal to normal system heat losses.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power limit, the initial conditions exceed the conditions assumed for the Reference 1 and 2 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > 90°F, increased monitoring of the pool temperature is required to ensure it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 90°F with THERMAL POWER > 1% RTP when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, the testing must be immediately suspended to preserve the pool heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 within 36 hours is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when pool temperature is > 110°F, increased monitoring of pool temperature is required to ensure that it remains ≤ 120°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours and the plant must be brought 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 without challenging plant systems.

Continued addition of heat to the suppression pool with pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

temperature or pressure. Furthermore, if a blowdown were to occur when temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of at least one OPERABLE post accident monitoring instrumentation channel in each suppression pool quadrant. Alternatively, average temperature can be determined by taking an arithmetic average of 10 OPERABLE suppression pool water temperature channels, which are distributed in different suppression pool sectors. There is no divisional requirement with respect to the instrument channels for this SR. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Appendix 6A.10.1.
3. NUREG-0783.
4. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND	The primary containment utilizes a Mark II over/under pressure suppression configuration, with the suppression pool located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling (RCIC) System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 145,495 ft^3 at the low water level limit of 199 ft 6 inches and 154,794 ft^3 at the high water level limit of 201 ft. If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the S/RV quenchers, main vents, or RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified. If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive pool swell loads resulting from a Design Basis Accident (DBA) LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.
APPLICABLE SAFETY ANALYSES	Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Suppression pool water level satisfies Criteria 2 and 3 of Reference 2.
LCO	A limit that suppression pool water level be ≥ 199 ft 6 inches and ≤ 201 ft (referenced to mean sea level) is required to ensure that the primary containment conditions assumed for the safety analysis are met. Either the high or low water level limits were used in the safety analysis, depending upon which is conservative for a particular calculation.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced because of the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS—Shutdown."

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as the downcomers are covered, RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and the capability of the drywell and suppression pool sprays. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within specified limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To

(continued)

BASES

ACTIONS	B.1 and B.2 (continued) 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.
SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency has been shown to be acceptable based on operating experience. 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 suppression pool water level condition.
REFERENCES	1. USAR, Section 6.2. 2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains a pump and a heat exchanger and is manually initiated and independently controlled. The two RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchanger and returning it to the suppression pool. Service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink.

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to 212°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	suppression pool temperature is calculated to remain below the design limit. The RHR Suppression Pool Cooling System satisfies Criterion 3 of Reference 2.
LCO	During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the pump, a heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause both a release of radioactive material to primary containment and a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and the potential avoidance of a plant shutdown transient that could result in the need for the RHR suppression pool cooling subsystems to operate.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual and power operated valves in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1 (continued)

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

Verifying each required RHR pump develops a flow rate ≥ 7450 gpm, while operating in the suppression pool cooling mode with flow through the associated heat exchanger, ensures that the primary containment peak pressure and temperature can be maintained below the design limits during a DBA (Ref. 1). The flow is also a normal test of centrifugal pump performance required by ASME Section XI (Ref. 3). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice tests confirm component OPERABILITY and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section 6.2.
2. 10 CFR 50.36(c)(2)(ii).
3. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Spray System removes heat from the suppression chamber airspace. The suppression pool is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel (RPV) through safety/relief valves. The heat addition to the suppression pool results in increased steam in the suppression chamber, which increases primary containment pressure. Steam blowdown from a DBA can also bypass the suppression pool and end up in the suppression chamber airspace. Some means must be provided to remove heat from the suppression chamber so that the pressure and temperature inside primary containment remain within analyzed design limits. This function is provided by two redundant (except for the spray header, which is common) RHR suppression pool spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR suppression pool spray subsystems contains one pump, which is manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool to the suppression pool spray sparger. The suppression pool spray sparger is common to both subsystems. The sparger only accommodates a small portion of the total RHR pump flow; the remainder of the flow returns to the suppression pool through the suppression pool cooling return line (provided the associated valve is open). Thus, both suppression pool cooling and suppression pool spray functions are normally performed when the Suppression Pool Spray System is initiated. Either RHR suppression pool spray subsystem is sufficient to condense the steam from small bypass leaks from the drywell to the suppression chamber airspace during the postulated DBA.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break loss of coolant accidents. The intent of the analyses is to demonstrate that the pressure reduction capacity of the RHR Suppression Pool Spray System (in conjunction with the RHR Drywell Spray System) is adequate to maintain the primary containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit.

The RHR suppression pool spray satisfies Criterion 3 of Reference 2.

LCO

In the event of a DBA, a minimum of one RHR suppression pool spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one pump and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR suppression pool spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE RHR suppression pool spray subsystem is adequate to perform the primary containment bypass leakage mitigation function.

(continued)

BASES

ACTIONS

A.1 (continued)

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass mitigation capability. The 7 day Completion Time was chosen in light of the redundant RHR suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

With both RHR suppression pool spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce pressure in the primary containment are available.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual and power operated valves in the RHR suppression pool spray mode flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1 (continued)

acceptable since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.4.2

Verifying each required RHR pump develops a flow rate ≥ 450 gpm while operating in the suppression pool spray mode helps ensure that the primary containment pressure can be maintained below the design limits during a DBA (Ref. 1). The normal test of centrifugal pump performance required by Section XI of the ASME Code (Ref. 3) is covered by the requirements of LCO 3.6.2.3, "RHR Suppression Pool Cooling." The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section 6.2.2.2.
2. 10 CFR 50.36(c)(2)(ii).
3. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombiners eliminate the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiners are required to reduce the hydrogen and oxygen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor is cooled and returned to the suppression pool, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated, since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent primary containment hydrogen recombiner subsystems are provided. Each consists of controls located in the control room, a power supply, and a recombiner located in the reactor building. Recombination is accomplished by heating a hydrogen air mixture to > 1150°F. The resulting water vapor and discharge gases are cooled prior to discharge from the unit. Air flows through the unit at approximately 150 scfm, with a blower providing the motive force. A single recombiner is capable of maintaining the hydrogen and oxygen concentration in primary containment to ≤ 5.0 volume percent (v/o) (Ref. 3). Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate emergency bus and is provided with separate power panel and control panel.

Operating Procedures direct that the hydrogen and oxygen concentration in primary containment be monitored following a DBA and that the primary containment hydrogen recombiners be manually activated prior to the primary containment atmosphere reaching a bulk hydrogen and oxygen concentrations of 4.0 v/o and 4.5 v/o, respectively.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The primary containment hydrogen recombiners provide the capability of controlling the bulk hydrogen and oxygen concentrations in primary containment to less than a concentration of 5.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen/oxygen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen and oxygen generation is a LOCA.

Oxygen may accumulate in the primary containment following a LOCA as a result of:

a. Radiolytic decomposition of water in the Reactor Coolant System; or

b. Operation of relief valves in the Breathing and Service Air Systems.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System; or

c. Corrosion of metals and decomposition of organic materials in the primary containment.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Assumptions recommended by Reference 4 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with plant procedures, the peak hydrogen and oxygen concentrations in the primary containment remains ≤ 5.0 v/o (Ref. 3).

The primary containment hydrogen recombiners satisfy Criterion 3 of Reference 5.

(continued)

BASES (continued)

LCO

Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner in the event of a worst case single active failure.

Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post LOCA hydrogen and oxygen concentrations can be prevented from exceeding their flammability limit.

APPLICABILITY

In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen and oxygen concentrations within primary containment below their limit of 5.0 v/o following a LOCA, assuming a worst case single failure.

In MODE 3, both the hydrogen and oxygen production rate and the total hydrogen and oxygen production after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiners are not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one primary containment hydrogen recombiner inoperable, the inoperable primary containment hydrogen recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE primary containment recombiner is adequate to perform the hydrogen and oxygen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen and oxygen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the amount of time available after the event for operator action to prevent hydrogen and oxygen

(continued)

BASES

ACTIONS

A.1 (continued)

accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the low probability of the failure of the OPERABLE recombiner, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limits.

B.1 and B.2

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen and oxygen control function via an alternate capability must be verified by administrative means within 1 hour. The alternate hydrogen and oxygen control capability is provided by the Primary Containment Vent, Purge, and Nitrogen System and one RHR drywell spray subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen and oxygen control function does not exist. In addition, the alternate hydrogen and oxygen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen and oxygen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen and oxygen control system. If the ability to perform the hydrogen and oxygen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen and oxygen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in the amounts capable of exceeding the flammability limits.

(continued)

BASES

ACTIONS (continued)

C.1

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater coil outlet gas temperature increases to ≥ 1150°F in ≤ 1.5 hours and that it is maintained ≥ 1150°F for ≥ 4 hours to check the capability of the recombiner to properly function (and that significant heater elements are not burned out).

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.2

This SR requires performance of a resistance to ground test of each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 1.0E6 ohms, within 30 minutes following completion of a system functional test (SR 3.6.3.1.1) or heatup of the system to normal operating temperature.

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. USAR, Section 6.2.5.
4. Regulatory Guide 1.7, Revision 2, November 1978.
5. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND	The primary containment is designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") and the RHR Drywell Spray System (LCO 3.6.1.6, "RHR Drywell Spray") to provide redundant and diverse methods to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain ≤ 5.0 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.
APPLICABLE SAFETY ANALYSES	The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced. Primary containment oxygen concentration satisfies Criterion 2 of Reference 2.

(continued)

BASES (continued)

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen and oxygen does not result in a combustible mixture inside primary containment.

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen and oxygen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is < 15% RTP, the potential for an event that generates significant hydrogen and oxygen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the availability of other hydrogen and oxygen mitigating systems (e.g., hydrogen recombiners) and the low probability and long duration of an event that would generate significant amounts of hydrogen and oxygen occurring during this period.

(continued)

BASES

ACTIONS (continued)	B.1 If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.3.2.1 The primary containment must be determined to be inerted by verifying that oxygen concentration is < 4.0 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which could lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.
REFERENCES	1. USAR, Section 6.2.5. 2. 10 CFR 50.36(c)(2)(ii).

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). 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 prior to release to the environment and to isolate and contain 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 (consisting of the reactor building and auxiliary bay structures) is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid, with the exception of the ASME III Code Class 1 piping and valves in the steam tunnel (Ref. 1). 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/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. 2), and a fuel handling accident (Ref. 3). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	and that fission products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment. Secondary containment satisfies Criterion 3 of Reference 4.
LCO	An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and 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	<u>A.1</u> 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

(continued)

BASES

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of

(continued)

BASES

ACTIONS

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

reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations 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 secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases, a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times; i.e., all inner doors closed or all outer doors closed. Thus, each access opening has one door closed. However all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.3 (continued)

performed on an access opening. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 2670 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that the secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds with the initial secondary containment pressure ≥ 0 psig, using one SGT subsystem. SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm. This flow rate is the assumed secondary containment leak rate during the drawdown period. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The drawdown test conditions must be adjusted based on the methodology in Reference 5 to compensate for actual inleakage flow and initial conditions during the test. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 3.6A.2.1.5.
2. USAR, Section 15.6.5.
3. USAR, Section 15.7.4.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 6.2.3.4.

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, that are released during certain operations when primary containment is not required to be OPERABLE, or that 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 are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs (i.e., dampers) 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 (which includes plugs and caps as listed in Reference 3).

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. 1) and a fuel handling accident (Ref. 2). The secondary containment performs no active function in response to each 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 (SGT) System before being released to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment. SCIVs satisfy Criterion 3 of Reference 4.
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, along with their associated stroke times, are listed in Reference 3. The normally closed manual SCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3.
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, 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 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	The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is

(continued)

BASES

ACTIONS (continued)

in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when the need for secondary containment isolation is indicated.

The second Note provides clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) 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 criteria are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

D.1, D.2, and D.3

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

added assurance that the SCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.3 (continued)

Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. Technical Requirements Manual.
4. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (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) 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.

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

a. A moisture separator;

b. An electric heater;

c. A prefilter bank;

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

e. A charcoal adsorber bank;

f. A second HEPA filter bank; and

g. A centrifugal fan.

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis. The internal pressure of the SGT System boundary region is maintained at a negative pressure of $\geq$ 0.25 inch water gauge when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building.

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than 70% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and

(continued)

BASES

BACKGROUND (continued)	protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter is provided to collect any carbon fines exhausted from the charcoal adsorber. The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both fans will start and the associated train inlet and fan discharge valves will open. Negative pressure in the reactor building is automatically controlled by the SGT System filter train recirculation line pressure control valves.
APPLICABLE SAFETY ANALYSES	The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Refs. 3 and 4). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment. The SGT System satisfies Criterion 3 of Reference 5.
LCO	Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under 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.

(continued)

BASES (continued)

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

C.1, C.2.1, C.2.2, and C.2.3

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable,

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1, E.2, and E.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating (from the control room using the manual initiation switch) each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of 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 SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 6). 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). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation 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. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.3.4

This SR requires verification that the SGT decay heat removal air inlet valves can be opened. This ensures that the decay heat removal mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.5.1.2.2.
3. USAR, Section 15.6.5.
4. USAR, Section 15.7.4.
5. 10 CFR 50.36(c)(2)(ii).
6. Regulatory Guide 1.52, Rev. 2.

B 3.7 PLANT SYSTEMS

B 3.7.1 Service Water (SW) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The SW System is designed to provide cooling water for the removal of heat from unit auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, emergency diesel generator (DG) coolers, and room coolers for Emergency Core Cooling System equipment required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The SW System also provides cooling to unit components, as required, during normal operation and shutdown conditions. During a loss of offsite power (LOOP) or loss of coolant accident (LOCA) coincident with a LOOP, the SW supply header cross connect valves (these valves are open to crosstie the supply headers of the two SW subsystems) are closed and the non-safety related equipment required for normal operation is isolated (both supply and return flow paths) from the SW System, and cooling is directed only to safety related equipment. However, if a partial LOOP occurs (i.e., one offsite circuit is lost, resulting in deenergization of either the Division 1 or Division 2 4.16 kV emergency bus), while the non-safety related equipment is still isolated, the SW supply header cross connect valves will not isolate. In addition, during the LOOP or LOCA/LOOP, one pump in each subsystem is restarted automatically in timed sequence (provided the associated pump discharge valve has automatically closed). If a pump fails to restart, a standby pump is started automatically to ensure one pump is running in each subsystem. During a LOCA (without a coincident LOOP), the SW pumps which are running remain in service (no SW pumps are automatically started on a LOCA signal), the SW supply headers remain crosstied (the SW supply header cross connect valves are not automatically closed), and the non-safety related loads are not isolated from the SW System.

The SW System consists of the UHS, two essential cooling water headers (subsystems A and B), and their associated pumps, piping, valves, and instrumentation. The SW System is sized such that any three pumps will provide sufficient cooling capacity to support the required safety related systems during safe shutdown of the unit following a LOCA. Subsystems A and B are redundant and service equipment in SW Divisions 1 and 2, respectively.

(continued)

BASES

BACKGROUND (continued)

The UHS consists of Lake Ontario and the SW Intake and Discharge System. The SW Intake System includes the two intake structures, the Intake Deicer Heating System, and the SW pump intake bay. The UHS is capable of providing sufficient cooling for all SW System post LOCA cooling requirements for a 30 day period (Regulatory Guide 1.27, Ref. 1).

Cooling water is pumped from the SW pump intake bay of the UHS by the SW pumps to the essential components through the two main redundant supply headers (subsystems A and B). After removing heat from the components, the water is discharged to Lake Ontario via the SW pump discharge bay, the discharge tunnel, and the diffuser nozzles.

Subsystems A and B supply cooling water to redundant equipment required for a safe reactor shutdown. Additional information on the design and operation of the SW System and UHS along with the specific equipment for which the SW System supplies cooling water is provided in the USAR, Sections 9.2.1 and 9.2.5 and the USAR, Table 9.2-1 (Refs. 2, 3, and 4, respectively). The SW System is designed to withstand a single active failure, coincident with a loss of offsite power, without losing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

Following a DBA or transient, the SW System will operate automatically without operator action.

APPLICABLE SAFETY ANALYSES

Sufficient water inventory is available for all SW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the SW System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the USAR, Sections 9.2.1, 6.2, and 6.3, Chapter 15, and Appendix A (Refs. 2, 5, 6, 7, and 8 respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA. The SW System provides cooling water for the RHR suppression pool cooling mode to limit suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its intended function of limiting the release of radioactive materials to the environment following a LOCA. The SW System also

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BASES

APPLICABLE SAFETY ANALYSES (continued)

provides cooling to other components assumed to function during a LOCA (e.g., RHR and Low Pressure Core Spray Systems). Also, the ability to provide onsite emergency AC power is dependent on the ability of the SW System to cool the DGs.

The safety analyses for long term containment cooling were performed, as discussed in the USAR, Section 6.2.2 (Ref. 9), for a LOCA, and a LOCA concurrent with a LOOP. The worst case single failure affecting the performance of the SW System during a LOCA/LOOP is the failure of the Division 1 or 2 standby DG, which would in turn affect one SW subsystem. The analysis shows that two SW pumps in one subsystem are adequate to perform the long term containment cooling function (one SW pump is automatically started and is sufficient for the first 10 minutes of the accident sequence, while a second SW pump is manually started 10 minutes into the accident sequence and is necessary to meet the long term cooling requirements). The worst case single failure affecting performance of the SW System during a LOCA is the failure of one of the SW pumps. This is the most limiting analysis since the non-safety related loads are not isolated during a LOCA. The analysis shows that three SW pumps (the SW pumps can be in one subsystem since the SW supply headers must be crosstied) are adequate to perform the long term containment cooling function (three pumps remain running when the accident occurs and are sufficient for the first 10 minutes of the sequence, while the non-safety related equipment is manually isolated 10 minutes into the accident sequence to meet the long term cooling requirements). The SW flow assumed in the analyses is 7400 gpm to the RHR heat exchanger (USAR, Table 9.2-1A, Ref. 4). Reference 2 discusses SW System performance during these conditions. The UHS is also assumed in these analyses. The analyses assumed the UHS maximum temperature is 82°F and the minimum SW pump intake bay water level is 233.1 ft. In addition, both intake structures are assumed, with 14 intake deicer heaters OPERABLE and in operation in each intake structure. The required number of intake deicer heaters ensures that the necessary intake structure suction area is available during both a LOCA and a LOCA/LOOP. During a LOCA/LOOP, 14 heaters are available in one division (assuming a DG failure) per intake structure to support the two required SW pumps. During a LOCA, 14 heaters are available in each division (since power is not lost) per intake structure to support the three required pumps. Therefore, the LOCA/LOOP is the most limiting condition for

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the intake deicer heater requirements. In addition, 14 heaters per intake structure will also ensure sufficient intake structure suction area is available during normal operations.

The SW System, together with the UHS, satisfy Criterion 3 of Reference 10.

LCO

The OPERABILITY of subsystem A (Division 1) and subsystem B (Division 2) of the SW System is required to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring both subsystems to be OPERABLE ensures that either subsystem A or B will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure.

A subsystem is considered OPERABLE when:

a. Two pumps are OPERABLE; and

b. The associated piping, valves (including the SW supply header cross connect valve and non-safety related supply and return isolation valves), instrumentation, and controls required to perform the safety related function are OPERABLE. In addition, the SW supply header cross connect valve must also be open to be OPERABLE.

OPERABILITY of the UHS is based on a maximum water temperature of 82°F, a minimum SW pump intake bay water level of 233.1 ft mean sea level, and 14 intake deicer heaters (of the 21 installed) OPERABLE (which includes being in operation) per division in each intake structure, when the intake tunnel water temperature is < 38°F.

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

Four SW pumps are required to be in operation since the SW pumps do not receive an automatic start on a LOCA signal. There are no restrictions as to the allowed combinations of operating SW pumps (i.e., two SW pumps in each subsystem or

(continued)

BASES

LCO (continued)

three SW pumps in one subsystem and one SW pump in the other subsystem are allowed), since any combination of four operating SW pumps will meet the accident analysis assumptions.

APPLICABILITY

In MODES 1, 2, and 3, the SW System and UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the SW System and UHS, and are required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the SW System and UHS are determined by the systems they support and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the systems supported by the SW System and UHS will govern SW System and UHS OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1 and A.2

If one SW supply header cross connect valve is inoperable due to being closed, an assumption of the LOCA analysis is not met. Therefore, the SW supply header cross connect valve must be opened within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem and takes into account the low probability of a LOCA occurring during this time. If one SW supply header cross connect valve is inoperable due to being incapable of automatically closing, the remaining OPERABLE SW supply header cross connect valve is adequate to ensure the two Divisions can be split, thus ensuring the SW heat removal function is maintained during a LOOP or LOOP/LOCA. However, the overall reliability is reduced because a single failure of the OPERABLE SW supply header cross connect valve could result in loss of the SW function during a LOOP or LOOP/LOCA. Therefore, the SW supply header cross connect valve must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE SW supply header cross connect valve and the low probability of a LOOP or LOOP/LOCA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

When one or more non-safety related SW flow paths (i.e., the two supply and two return flow paths) have one SW isolation valve that is inoperable, the remaining OPERABLE SW isolation valve in each affected non-safety related SW flow path is adequate to ensure the non-safety related flow paths can be isolated from the safety related flow paths, thus ensuring the SW heat removal function is maintained. However, the overall reliability is reduced because a single failure of the OPERABLE SW isolation valve in an affected non-safety related flow path could result in loss of the SW function during a LOOP or LOOP/LOCA. Therefore, the affected non-safety related flow path(s) must be isolated within 72 hours. Isolating the affected non-safety related flow path(s) is acceptable since this action performs the function of the SW isolation valves. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE SW isolation valve in each affected non-safety related flow path and the low probability of a LOOP or LOOP/LOCA occurring during this period.

C.1

If one SW subsystem is inoperable for reasons other than Conditions A and B (e.g., one or two required SW pumps inoperable in one subsystem), it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE SW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SW subsystem could result in a loss of the SW function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

D.1

If one division of intake deicer heaters is inoperable, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE deicer heater division is adequate to ensure both intake structures

(continued)

BASES

ACTIONS

D.1 (continued)

remain free of ice blockage, thus ensuring the UHS is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE intake deicer heater division could result in loss of the UHS function during a DBA. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE intake deicer heater division and the low probability of a DBA occurring during this period.

E.1

If one required SW pump is not in operation, it must be restored to operation within 72 hours. With the unit in this condition, the remaining operating SW pumps are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure of a remaining operating pump could result in loss of the SW function during a DBA LOCA. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the operating pumps and the low probability of a DBA LOCA occurring during this period.

F.1

If two or more required SW pumps are not in operation, three SW pumps must be in operation within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem and is consistent with the 1 hour provided in LCO 3.0.3. This time period also takes into account the low probability of a DBA LOCA occurring during this time.

G.1 and G.2

If any Required Action and associated Completion Time of Condition A, B, C, D, E, or F are not met, or both SW subsystems are inoperable for reasons other than Conditions A, B, and C, or the UHS is inoperable for reasons other than Condition D, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note indicating that the applicable Conditions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable SW System or UHS results in an inoperable RHR shutdown cooling subsystem. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for the RHR Shutdown Cooling System.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verification that the water temperature of the intake tunnels is ≥ 38°F ensures that frazil ice, which can block the intake tunnels, cannot form. This ensures that the intake tunnels can perform their intended function. This Surveillance is only required to be met when SR 3.7.1.5 and SR 3.7.1.8 are not satisfied. With the Intake Deicer Heater System OPERABLE (and SR 3.7.1.5 and SR 3.7.1.8 met), frazil ice cannot form even with the intake tunnels water temperature < 38°F. The 12 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

This SR verifies the water level in the SW pump intake bay to be sufficient for the proper operation of the SW pumps (net positive suction head and pump vortexing are considered in determining this limit). The water level limit, 233.1 ft, is referenced to mean sea level. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.3

Verification of each SW subsystem supply header temperature ensures that the heat removal capability of the SW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. However, if a SW subsystem supply header water temperature is ≥ 75°F, the Surveillance must be performed more frequently (every 4 hours if ≥ 75°F and every 2 hours if ≥ 79°F), since the condition is closer to the maximum water temperature limit.

SR 3.7.1.4

Verification that each required SW pump is in operation ensures that an adequate number of SW pumps are operating to perform the long term containment cooling function during a LOCA. The 24 hour Frequency is based on operating experience and the operator's inherent knowledge of plant status, including changes in SW pump operating status.

SR 3.7.1.5

The current for each required heater feeder cable is required to be checked to ensure the proper number of heaters are OPERABLE for each intake deicer heater division. The Surveillance is performed by verifying, at the motor control centers, that the current is ≥ 20 amps (total for all three phases when adjusted to degraded voltage conditions, i.e., 518 volts) in each intake structure for each division. The current limit is based upon ensuring 14 heaters are OPERABLE (which includes in operation) in an intake structure. This Surveillance is only required to be met when SR 3.7.1.1 is not satisfied, since with the intake tunnels water temperature ≥ 38°F (i.e., SR 3.7.1.1 met), frazil ice cannot form even with the intake deicer heaters inoperable. The 7 day Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.6

Verifying the correct alignment for each manual, power operated, and automatic valve in each SW subsystem flow path provides assurance that the proper flow paths will exist for SW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the associated SW subsystem to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the SW subsystem. As such, when all SW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SW subsystem is still OPERABLE.

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

SR 3.7.1.7

This SR verifies that the automatic isolation valves (i.e., SW isolation valves servicing non-safety related equipment, SW supply header cross connect valves, and SW pump discharge valves of non-operating SW pumps) of the SW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during a transient event (i.e., LOOP). This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the SW pump (and associated pump discharge valve opening capability) in each subsystem.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.7 (continued)

Operating experience has shown that these components usually pass the SR when performed on the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

SR 3.7.1.8

The resistance of each required heater feeder cable and associated heater elements is required to be checked to ensure the required heaters are OPERABLE for each intake deicer heater division. The Surveillance is performed by verifying that the resistance is ≥ 28 ohms for each required heater feeder cable and associated heater element. The minimum resistance is based on ensuring the intake structure bar racks are heated sufficiently such that the SW flow assumed to safely shutdown the unit can be achieved through the intake structures. This Surveillance is only required to be met when SR 3.7.1.1 is not satisfied, since with the intake tunnels water temperature ≥ 38°F (i.e., SR 3.7.1.1 met), frazil ice cannot form even with the intake deicer heaters inoperable. The 24 month Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.1.
3. USAR, Section 9.2.5.
4. USAR, Tables 9.2-1 and 9.2-1A.
5. USAR, Section 6.2.
6. USAR, Section 6.3.
7. USAR, Chapter 15.
8. USAR, Appendix A.
9. USAR, Section 6.2.2.
10. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.2 Control Room Envelope Filtration (CREF) 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 control room envelope consists of all rooms and areas located in the main control room and relay room of the control building. Included in the envelope are the main control room, relay room, instrument shop, training room, shift supervisor's office, lunch room, toilets, corridors, work release room, and HVAC equipment rooms (Ref. 1).

The safety related function of the CREF System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air and outside supply air. Each subsystem includes a control room outdoor air special filter train (CROASFT), which consists of an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a filter booster fan, and the associated ductwork and dampers. The electric heater is used to limit the relative humidity of the air entering the filter train. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay. Each subsystem also includes the necessary outside air intake(s) and two air conditioning units (fan portion only), one for the control room and one for the relay room. Each outside air intake is capable of providing 100% of the necessary makeup flow. Therefore, normally only one outside air intake is necessary. However, when the unit is in MODE 1, 2, or 3 with MSIV leakage > 15 scfh for any MSIV, both outside air intakes, including the capability to isolate the intakes, are necessary. Both outside air intakes are required in these conditions since the accident analysis assumes the most contaminated outside air intake is isolated 8 hours after the accident to ensure the dose to control room envelope personnel does not exceed the limit. The outside air intake that is not isolated continues to be capable of providing 100% of the necessary makeup flow. The two required outside air intakes are allowed to be common to both subsystems (since there are only two outside air intakes for the CREF System). Alternately, if MSIV leakage

(continued)

BASES

BACKGROUND (continued)

is > 15 scfh for any MSIV, an additional analysis may be performed to determine the "effective" MSIV leakage. The "effective" MSIV leakage is the individual MSIV leak rate when all four main steam lines are assumed to leak at the same rate, and the doses in the control room envelope are equivalent to those when the individual "as-left" valve leak rates are used. If the "effective" MSIV leakage is ≤ 15 scfh, then only one outside air intake is necessary.

The CROASFT portion of the safety related CREF System is normally in standby, but the remaining portions of the CREF System (the outside air intakes and fan portion of the air conditioning units) are operated to maintain the control room envelope environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room envelope personnel), the CREF System automatically switches to the emergency pressurization mode of operation to prevent infiltration of contaminated air into the control room envelope. A system of valves and dampers redirects all control room envelope outside air flow through the two CROASFTs. In addition, a portion of the control room air is recirculated through the CROASFTs. The air conditioning units (fan portion only) maintain the 1/8 inch positive pressure; the CROASFT booster fan only provides the motive force to overcome the added resistance of the CROASFT being in service.

The CREF System is designed to maintain the control room envelope environment for a 30 day continuous occupancy (i.e., considering the occupancy factors of NUREG-0800, Table 6.4-1, Ref. 2) after a DBA, while limiting the dosage to personnel to not more than 5 rem whole body or its equivalent to any part of the body. CREF System operation in maintaining the control room envelope habitability is discussed in the USAR, Sections 6.4.1 and 9.4.1 (Refs. 3 and 4, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the CREF System to maintain the habitability of the control room envelope is an explicit assumption for the safety analyses presented in the USAR, Chapters 6 and 15 (Refs. 5 and 6, respectively). The emergency pressurization mode of the CREF System is assumed to operate following a loss of coolant accident, main steam line break, fuel handling accident, and control rod drop accident. The radiological doses to control room envelope personnel as a result of the various DBAs are summarized in Reference 6.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

No single active failure will cause the loss of outside or recirculated air from the control room envelope.

The CREF System satisfies Criterion 3 of Reference 7.

LCO

Two redundant subsystems of the CREF System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. 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 in both subsystems. A subsystem is considered OPERABLE when its associated:

a. CROASFT is OPERABLE;

b. Air conditioning units (fan portion only) are OPERABLE (one for the control room and one for the relay room), including the ductwork, to maintain air circulation to and from the control room envelope; and

c. Necessary outside air intake(s) are OPERABLE. When the unit is not in MODES 1, 2, and 3, or when the unit is in MODE 1, 2, or 3 with MSIV leakage $\leq$ 15 scfh for each MSIV, only one outside air intake is necessary. When the unit is in MODE 1, 2, or 3 with MSIV leakage > 15 scfh for any MSIV, both outside air intakes, including the capability to isolate the intakes, are necessary and are allowed to be common to both subsystems. Alternately, if MSIV leakage is > 15 scfh for any MSIV, an additional analysis may be performed to determine the "effective" MSIV leakage. If the "effective" MSIV leakage is $\leq$ 15 scfh, then only one outside air intake is necessary.

A CROASFT is considered OPERABLE when its associated filter booster fan is OPERABLE; HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and heater, ductwork, valves, and dampers are OPERABLE, and air circulation through the filter train can be maintained.

In addition, the control room envelope boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors, such that the

(continued)

BASES

LCO (continued)	pressurization limit of SR 3.7.2.4 can be met. However, it is acceptable for access doors to be open for normal control room envelope entry and exit and not consider it to be a failure to meet the LCO.

APPLICABILITY

In MODES 1, 2, and 3, the CREF System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CREF System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During movement of irradiated fuel assemblies in the secondary containment;

b. During CORE ALTERATIONS; and

c. During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

A.1

With one CREF subsystem inoperable, or with both CREF subsystems inoperable but the CREF System safety function maintained, the inoperable CREF subsystem(s) must be restored to OPERABLE status within 7 days. The CREF System safety function is maintained when the CREF System components equivalent to one CREF subsystem are OPERABLE. With the unit in this condition, the remaining OPERABLE CREF subsystem (or OPERABLE components in both subsystems) is adequate to perform the control room envelope radiation protection function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem (or remaining OPERABLE portions of the subsystems, as applicable) could result in loss of CREF System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem (or components in both subsystems) can provide the required capabilities.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable CREF subsystem(s) cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable CREF subsystem(s) cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE components of the CREF subsystem(s) equivalent to a single CREF subsystem (e.g., the CROASFT and fan portion of the air conditioning units do not have to be powered from the same electrical division) may be placed in the emergency pressurization mode. This action ensures that the remaining subsystem (or components in both subsystems equivalent to a single CREF subsystem) is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

D.1

If both CREF subsystems are inoperable with the CREF System safety function not maintained in MODE 1, 2, or 3, the CREF System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two CREF subsystems inoperable with the CREF System safety function not maintained, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

Operating (from the control room) each CREF subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, filter booster or air conditioning unit fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain humidity, as necessary) for ≥ 10 continuous hours every 31 days reduces moisture on the adsorbers and HEPA filters. In addition, it is not necessary to operate all components of a single subsystem simultaneously for the 10 hour period. It is acceptable to operate the fan portion of the air conditioning unit(s) of one subsystem with the CROASFT of the other subsystem, such that the CROASFTs and fan portion of the air conditioning units are each operated for 10 continuous hours. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.7.2.2

This SR verifies that the required CROASFT testing is performed in accordance with Specification 5.5.7, "Ventilation Filter Testing Program (VFTP)." The CROASFT filter tests are in accordance with Regulatory Guide 1.52 (Ref. 8). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.3

This SR verifies that each CREF subsystem starts and operates on an actual or simulated initiation signal. This SR also includes ensuring the air conditioning units (fan portion only) start on a low flow signal after the appropriate time delay. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Control Room Envelope Filtration (CREF) System Instrumentation," overlaps this SR to provide complete testing of the safety function. Operating experience has shown that these components normally pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.7.2.4

This SR verifies the integrity of the control room envelope and the assumed inleakage rates of potentially contaminated air. The control room envelope positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the CREF System. The SR requires all combinations of the CREF System to be verified. This can be met by determining (by test) the worst combination of the air conditioning units (fan portion only), then testing the worst combination of the air conditioning units (fan portion only) with each CROASFT. During the emergency pressurization mode of operation, the CREF System is designed to slightly pressurize the control room envelope to ≥ 0.125 inches water gauge positive pressure with respect to outside atmosphere to prevent unfiltered inleakage. The CREF System is designed to maintain this positive pressure at an outside air intake flow rate of ≤ 1500 cfm to the control room envelope in the emergency pressurization mode. Compliance with this SR is demonstrated by measurement of the pressure in the control room and relay room, which are representative of adequate positive pressure in both elevations of the control room envelope. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs.

REFERENCES

1. USAR, Section 6.4.2.1.
2. NUREG-0800, Table 6.4-1.

(continued)

BASES

REFERENCES (continued)

3. USAR, Section 6.4.1.
4. USAR, Section 9.4.1.
5. USAR, Chapter 6.
6. USAR, Chapter 15.
7. 10 CFR 50.36(c)(2)(ii).
8. Regulatory Guide 1.52, Revision 2, March 1978.

B 3.7 PLANT SYSTEMS

B 3.7.3 Control Room Envelope Air Conditioning (AC) System

BASES

BACKGROUND	The control room envelope AC portion of the Control Building Heating, Ventilation, and Air Conditioning (HVAC) System (hereafter referred to as the Control Room Envelope AC System) provides temperature control for the control room envelope following isolation of the control room envelope. The Control Room Envelope AC System consists of two independent, redundant subsystems that provide cooling of recirculated and outside air makeup control room envelope air. Each subsystem consists of two air conditioning units (one for the control room and one for the relay room), one control building chilled water subsystem (which provides cooling water to the cooling coils of the two air conditioning units), ductwork, dampers, and instrumentation and controls to provide for control room envelope temperature control. Each air conditioning unit includes an air filter assembly, cooling coil, and fan. Each control building chilled water subsystem includes a hermetic centrifugal water chiller, chilled water pump, expansion tank, controls, piping, and valves. The Control Room Envelope AC System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room envelope environment for a sustained occupancy of 37 persons. The design conditions for the control room envelope environment are 75°F and 50% relative humidity. The Control Room Envelope AC System operation in maintaining the control room envelope temperature is discussed in the USAR, Sections 6.4 and 9.4.1 (Refs. 1 and 2, respectively).
APPLICABLE SAFETY ANALYSES	The design basis of the Control Room Envelope AC System is to maintain the control room envelope temperature for a 30 day continuous occupancy following isolation of the control room envelope. The Control Room Envelope AC System components are arranged in redundant safety related subsystems. During emergency operation, the Control Room Envelope AC System maintains a habitable environment and ensures the OPERABILITY of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

components in the control room envelope. A single active failure of a component of the Control Room Envelope AC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room envelope temperature control. The Control Room Envelope AC System is designed in accordance with Seismic Category I requirements. The Control Room Envelope AC System is capable of removing sensible and latent heat loads from the control room envelope, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

The Control Room Envelope AC System satisfies Criterion 3 of Reference 3.

LCO

Two independent and redundant subsystems of the Control Room Envelope AC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The Control Room Envelope AC System is considered OPERABLE when the individual components necessary to maintain the control room envelope temperature are OPERABLE in both subsystems. These components include the control room and relay room air conditioning units (cooling coils and fans only), the control building chilled water subsystems, ductwork, dampers, and associated instrumentation and controls. In addition, during conditions in MODES other than MODES 1, 2, and 3 when the Control Room Envelope AC System is required to be OPERABLE (e.g., during CORE ALTERATIONS), the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the hermetic centrifugal water chillers are part of the OPERABILITY requirements covered by this LCO.

APPLICABILITY

In MODE 1, 2, or 3, the Control Room Envelope AC System must be OPERABLE to ensure that the control room envelope temperature will not exceed equipment OPERABILITY limits following control room envelope isolation.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and

(continued)

BASES

APPLICABILITY (continued)

temperature limitations in these MODES. Therefore, maintaining the Control Room Envelope AC System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During movement of irradiated fuel assemblies in the secondary containment;

b. During CORE ALTERATIONS; and

c. During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

A.1

With one control room envelope AC subsystem inoperable, or with both control room envelope AC subsystems inoperable but the Control Room Envelope AC System safety function maintained, the inoperable control room envelope AC subsystem(s) must be restored to OPERABLE status within 30 days. The Control Room Envelope AC System safety function is maintained when the Control Room Envelope AC System components equivalent to one control room envelope AC subsystem are OPERABLE. With the unit in this condition, the remaining OPERABLE control room envelope AC subsystem (or OPERABLE components in both subsystems) is adequate to perform the control room envelope air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem (or remaining OPERABLE portions of the subsystems, as applicable) could result in loss of the control room envelope air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room envelope isolation, the consideration that the remaining subsystem (or components in both subsystems) can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable control room envelope AC subsystem(s) cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status the unit

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE components of the control room envelope AC subsystem(s) equivalent to a single control room envelope AC subsystem (e.g., the control building chilled water subsystem and air conditioning units do not have to be powered from the same electrical division) may be placed immediately in operation. This action ensures that the remaining subsystem (or components in both subsystems equivalent to a single control room envelope AC subsystem) is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

D.1

If both control room envelope AC subsystems are inoperable with the Control Room Envelope AC System safety function not maintained in MODE 1, 2, or 3, the Control Room Envelope AC System may not be capable of performing the intended function. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs with two control room envelope AC subsystems inoperable with the Control Room Envelope AC System safety function not maintained, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room envelope heat load assumed in the safety analyses. The SR consists of a combination of testing and calculation. The 24 month Frequency is appropriate since significant degradation of the Control Room Envelope AC System is not expected over this time period.

REFERENCES

1. USAR, Section 6.4.
2. USAR, Section 9.4.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.4 Main Condenser Offgas

BASES

BACKGROUND	During unit operation, steam from the low pressure turbine is exhausted directly into the main condenser. Air and noncondensible gases are collected in the main condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and dryers. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the offgas dryers prior to entering the charcoal adsorbers.
APPLICABLE SAFETY ANALYSES	The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser Offgas System failure event as discussed in the USAR, Section 15.7.1 (Ref. 1). The analysis assumes a gross failure in the Main Condenser Offgas System that results in the rupture of the Main Condenser Offgas System pressure boundary. The gross gamma activity rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits (NUREG-1047, Ref. 2) of 10 CFR 100 (Ref. 3). The main condenser offgas limits satisfy Criterion 2 of Reference 4.
LCO	To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 100 μCi/Mwt-second after decay of 30 minutes. The LCO is established consistent with this requirement (3536 Mwt x 100 μCi/Mwt-second ≈ 350,000 μCi/second).

(continued)

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, main steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from significant sources of radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample (taken before holdup and discharge downstream of the recombiner) to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly as indicated by either offgas pretreatment radiation monitor (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. USAR, Section 15.7.1.
2. NUREG-1047.
3. 10 CFR 100.
4. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.5 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is approximately 22% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a five valve manifold connected to the main steam lines between the main steam isolation valves and the main turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the USAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the valve manifold, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in the USAR, Section 15.1.2 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in an MCPR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of Reference 3.

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow continued operation.

An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2). The MCPR limit for the inoperable Main Turbine Bypass System is specified in the COLR.

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.2, sufficient margin to this limit exists < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), and the MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

(continued)

BASES

ACTIONS (continued)

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status and the MCPR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.7.5.2

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in the Technical Requirements Manual (Ref. 4). While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 7.7.1.5.
2. USAR, Section 15.1.2.
3. 10 CFR 50.36(c)(2)(ii).
4. Technical Requirements Manual.

B 3.7 PLANT SYSTEMS

B 3.7.6 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident.

A general description of the spent fuel storage pool design is found in the USAR, Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in the USAR, Section 15.7.4 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident (Ref. 2). A fuel handling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are ≤ 25% (NUREG-0800, Section 15.7.4, Ref. 3) of the 10 CFR 100 (Ref. 4) exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 5).

The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core. The consequences of a fuel handling accident over the spent fuel storage pool are less severe than those of the fuel handling accident over the reactor core (Ref. 2). The water level in the spent fuel storage pool provides for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident.

The spent fuel storage pool water level satisfies Criterion 2 of Reference 6.

LCO

The specified water level preserves the assumption of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.

(continued)

BASES (continued)

APPLICABILITY

This LCO applies whenever movement of irradiated fuel assemblies occurs in the spent fuel storage pool or whenever movement of new fuel assemblies occurs in the spent fuel storage pool with irradiated fuel assemblies in the spent fuel storage pool, since the potential for a release of fission products exists.

ACTIONS

A.1

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since fuel assembly movement can occur in MODE 1, 2, or 3, Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of fuel assembly movement are not postponed due to entry into LCO 3.0.3.

When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With the spent fuel storage pool level less than required, the movement of fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of a fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable and water level changes are controlled by unit procedures.

REFERENCES

1. USAR, Section 9.1.2.
2. USAR, Section 15.7.4.

(continued)

BASES

REFERENCES (continued)

3. NUREG-0800, Section 15.7.4, Revision 1, July 1981.
4. 10 CFR 100.
5. Regulatory Guide 1.25, March 1972.
6. 10 CFR 50.36(c)(2)(ii).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, Divisions 1, 2, and 3, with each division powered by an independent Class 1E 4.16 kV emergency bus (refer to LCO 3.8.8, "Distribution Systems—Operating"). The Division 1 and 2 4.16 kV emergency buses each have one separate and independent offsite source of power. The Division 3 4.16 kV emergency bus can be supplied by either offsite source. Each 4.16 kV emergency bus has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the transmission network. From the switchyard three qualified, electrically and physically separated circuits provide AC power to the Division 1, 2, and 3 4.16 kV emergency buses. Offsite power source A, Reserve Station Service Transformer 2RTX-XSR1A (115 kV/13.8 kV/4.16 kV), provides power to the Division 1 4.16 kV emergency bus and also is normally lined up to provide power to the Division 3 4.16 kV emergency bus. Offsite power source B, Reserve Station Service Transformer 2RTX-XSR1B (115 kV/13.8 kV/4.16 kV), provides power to the Division 2 4.16 kV emergency bus and, when aligned, is capable of providing power to the Division 3 4.16 kV emergency bus. In addition, either Division 1 or Division 2 4.16 kV emergency bus can be powered from a third qualified source, the Auxiliary Boiler Transformer 2ABS-X1. The offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A

(continued)

BASES

BACKGROUND (continued)

detailed description of the offsite power network and circuits to the onsite Class 1E 4.16 kV emergency buses is found in USAR, Chapter 8 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E 4.16 kV emergency bus(es).

Following an accident signal, certain required Division 1 and 2 plant loads are started in a predetermined sequence in order to prevent overloading the reserve station service transformer supplying offsite power to the onsite Class 1E Distribution System. The starting sequence of all automatically connected loads needed to recover the unit or maintain it in a safe condition is provided in Reference 3.

The onsite standby power source for each 4.16 kV emergency bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., low reactor water level signal; Level 1 for Division 1 and 2 DGs, Level 2 for Division 3 DG, or high drywell pressure signal) or on an emergency bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation"). After the DG has started, it automatically ties to its respective 4.16 kV emergency bus after offsite power is tripped as a consequence of emergency 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 4.16 kV emergency bus on a LOCA signal alone.

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

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the DG. For Divisions 1 and 2, if a loss of offsite power signal or a loss of offsite power signal concurrent with a LOCA signal is received, all loads on the respective 4.16 kV emergency bus, including the stub bus, are shed (except the

(continued)

BASES

BACKGROUND (continued)

600 V load centers), and the emergency loads are sequentially started once power is restored. The Division 3 bus has no shedding or sequencing.

Division 1 and 2 DGs (EDG1 and EDG3) satisfy the following Regulatory Guide 1.9 (Ref. 4) ratings:

a. 4400 kW - continuous;

b. 4750 kW - 2000 hours; and

c. 4840 kW - 2 hours.

Division 3 DG (EDG2) satisfies the following Regulatory Guide 1.9 (Ref. 4) ratings:

a. 2600 kW - continuous;

b. 2850 kW - 2000 hours;

c. 2950 kW - 200 hours;

d. 2860 kW - 2 hours; and

e. 3050 kW - 30 minutes.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the USAR, Chapter 6 (Ref. 5) and Chapter 15 (Ref. 6), 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:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of Reference 7.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs, ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

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

Each offsite circuit from the 345 kV/115 kV Scriba Substation must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the 4.16 kV emergency buses. Each offsite circuit consists of the incoming breaker and disconnect to the respective reserve station service transformers 2RTX-XSR1A and 2RTX-XSR1B and auxiliary boiler transformer 2ABS-X1, the respective 2RTX-XSR1A, 2RTX-XSR1B, and 2ABS-X1 transformers, and the respective circuit path including feeder breakers to the 4.16 kV emergency buses. In addition, proper sequencing of loads is a required function for offsite circuit OPERABILITY.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 13.20 seconds. The 13.20 second start time includes the Loss of Voltage—Time Delay Function Allowable Value specified in LCO 3.3.8.1. 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 4.16 kV emergency buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while

(continued)

BASES

LCO (continued)

operating in parallel test mode. Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical.

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 AOOs or abnormal transients; and

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

A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS entered, the Division 3 AC sources provide no additional assurance of meeting the above criteria.

AC power requirements for MODES 4 and 5 and other conditions in which AC sources are required are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if the second required

(continued)

BASES

ACTIONS

A.1 (continued)

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, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 Emergency Core Cooling Systems (ECCS)). 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 for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

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

b. A redundant required feature on another 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 begins to be tracked.

Discovering no offsite power to one division of the onsite Class 1E Power Distribution System coincident with one or more inoperable redundant required support or supported features, or both, that are associated with the other division that has offsite power, results in starting the

(continued)

BASES

ACTIONS

A.2 (continued)

Completion Time 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 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

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition A for a period that should not exceed 72 hours.

This Completion Time assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. In the event both the HPCS and Low Pressure Core Spray (LPCS) Systems are without offsite power, this assumption is not met. Therefore, the optional Completion Time is specified. Should the HPCS and LPCS Systems be affected, the 24 hour Completion Time is conservative with respect to the Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable. 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.

(continued)

BASES

ACTIONS

A.3 (continued)

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

The third 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 72 hours. This situation could lead to a total of 144 hours, 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 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

Similar to Required Action A.2, the 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.

B.1

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

(continued)

BASES

ACTIONS (continued)

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of inoperable features associated with a division redundant to the division 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 another 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 required DG inoperable coincident with one or more redundant required support or supported features, or both, that are associated with the OPERABLE DG(s), results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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 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

(continued)

BASES

ACTIONS

B.2 (continued)

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(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E or G of LCO 3.8.1 is entered, as applicable. 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(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Deficiency Event Report 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. 9), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition B for a period that should not exceed 72 hours. In this condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS

B.4 (continued)

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Similar to Required Action B.2, the Completion Time of Required Action B.4 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 the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 8) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e.,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

single division systems are not included in the list, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

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

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 8), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any division (i.e., the division is de-energized), Actions for LCO 3.8.8, "Distribution Systems—Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

E.1

With two DGs inoperable, there is one remaining standby AC source. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 8), with two required DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with the other Division 1 or 2 DG remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent—an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is

(continued)

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ACTIONS

E.1 (continued)

appropriate. At the end of this 24 hour period, the Division 3 system (HPCS System) could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to 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.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 10). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 11), Regulatory Guide 1.108 (Ref. 12), and Regulatory Guide 1.137 (Ref. 13).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3950 V is approximately 95% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 14), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4370 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 11).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period. In addition, to minimize wear and tear on the DG, the Note

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

also allows all DG starts to be followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant (Division 1 and 2 DGs only) and lube oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 15). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 11). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0 when running synchronized with the grid. The 0.8 power factor value is the design rating of the machine at a particular KVA. The 1.0 power factor value is an operational condition where the reactive power component is zero, which minimizes the reactive heating of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

the generator. Operating the generator at a power factor between 0.8 lagging and 1.0 avoids adverse conditions associated with underexciting the generator and more closely represents the generator operating requirements when performing its safety function (running isolated on its associated 4.16 kV emergency bus). The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 11).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance must be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which the low-low level alarm is annunciated. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is most effective means in controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is established by Regulatory Guide 1.137 (Ref. 13). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each fuel oil transfer pump (two per DG) operates and automatically transfers fuel oil from its associated storage tank to its associated day tank. It is required to support the continuous operation of standby power sources. This Surveillance provides assurance that each fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE. Two fuel oil transfer pumps per DG are required since each pump only has a simplex strainer.

The Frequency for this SR is conservative with respect to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 16).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined frequency and while maintaining a specified margin to the overspeed trip. The load referenced for Division 1 DG is the 1125 kW low pressure core spray pump; for Division 2 DG, the 750 kW residual heat removal (RHR) pump; and for Division 3 DG the 2435 kW HPCS pump. The specified load values conservatively bound the expected kW rating of the single largest loads under accident conditions. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

Consistent with Regulatory Guide 1.9 (Ref. 11), the load rejection test is acceptable if the diesel speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower. This corresponds to ≤ 64.5 Hz for the Division 1 and 2 DGs and ≤ 66.75 Hz for the Division 3 DG, which is the nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed at a power factor as close to the power factor of the single largest post-accident load as practicable. The power factor limit is ≤ 0.92 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is representative of the actual design basis inductive loading that the DG could experience. However, since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.8

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.91 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is

(continued)

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

representative of the actual design basis inductive loading that the DG would experience.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.9

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads (Divisions 1 and 2 only) and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start and energization of permanently connected loads time of 13.20 seconds is derived from the 3.20 second Loss of Voltage—Time Delay Function Allowable Value (LCO 3.3.8.1) and the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 14). The Surveillance should be continued for a minimum of

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanently connected loads and auto-connected loads (Division 1 and 2 only) is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal). In addition,

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The DG is required to operate for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power (for Divisions 1 and 2 only).

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. This is only required for Divisions 1 and 2 because the loading logic is different based on the power source. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the AC electrical power system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths.

This SR is modified by two Notes. The reason for the Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed and generator differential current) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG and 2 hours of which is at a load equivalent to 105% to 110% of the continuous rating of the DG. The DG starts for this Surveillance can be performed

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.91 for Division 1 and 2 DGs and ≤ 0.93 for Division 3 DG. This power factor is representative of the actual design basis inductive loading that the DG could experience.

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. However, it is acceptable to perform this SR in MODES 1 and 2 provided the other two DGs are OPERABLE, since a perturbation can only affect one divisional DG. If during performance of this Surveillance one of the other DGs becomes inoperable, this Surveillance is to be suspended. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that since the offsite electrical power transmission network is not balanced, it may not be possible to raise DG voltage sufficiently to meet the power factor limit without one phase of the DG exceeding the current limit. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if the offsite grid phase imbalance does not permit the power factor limit to be met when the DG is tied to the grid.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

When this occurs, the power factor should be maintained as close to the limit as practicable.

SR 3.8.1.13

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 15). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG.

The 24 month Frequency takes into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at approximately full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

and can receive an auto-close signal on bus undervoltage, and the individual load timers are reset.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycles.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.15

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.13, demonstration of the parallel test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 17), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.10. The intent in the requirement associated with SR 3.8.1.15.b is to show that the emergency loading is not affected by the DG operation in parallel test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR has been modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.16

Under accident conditions loads are sequentially connected to the bus by the automatic load sequence time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The -10% load sequence time interval limit ensures that a sufficient time interval exists for the DG to restore frequency and voltage prior to applying the next load. There is no upper limit for the load sequence time interval since, for a single load interval (i.e., the time between two load blocks), the capability of the DG to restore frequency and voltage prior to applying the second load is not negatively affected by a longer than designed load interval, and if there are additional load blocks (i.e., the design includes multiple load intervals), then the lower limit requirements (-10%) will ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the remaining load blocks (i.e., all load intervals must be ≥ 90% of the design interval). Reference 2 provides a summary of the automatic loading of emergency buses. Since only the Division 1 and 2 DGs have more than one load block, this SR is only applicable to these DGs.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.9, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. Since the Loss of Voltage—Time Delay Functions are bypassed during an ECCS initiation signal, a 10 second DG start time applies. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with an expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.18

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper frequency and voltage within the specified time when the DGs are started simultaneously.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.14.

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. USAR, Tables 8.3-1, 8.3-2, and 8.3-3.
4. Regulatory Guide 1.9, Revision 2, December 1979.
5. USAR, Chapter 6.
6. USAR, Chapter 15.
7. 10 CFR 50.36(c)(2)(ii).
8. Regulatory Guide 1.93, Revision 0, December 1974.
9. Generic Letter 84-15, July 2, 1984.
10. 10 CFR 50, Appendix A, GDC 18.
11. Regulatory Guide 1.9, Revision 3, July 1993.
12. Regulatory Guide 1.108, Revision 1, August 1977.
13. Regulatory Guide 1.137, Revision 1, October 1979.
14. ANSI C84.1, 1982.
15. USAR, Section 15.6.5.
16. ASME, Boiler and Pressure Vessel Code, Section XI.
17. IEEE Standard 308-1980.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources—Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources—Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shutdown the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of Reference 1.

LCO

One offsite circuit supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.9, "Distribution Systems—Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with a Division 1 or Division 2 Distribution System emergency bus required OPERABLE by LCO 3.8.9, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) is required to be OPERABLE,

(continued)

BASES

LCO (continued)

a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensures an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a., or a circuit required to meet LCO Item c. may be connected, with the second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensure the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel draindown).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective emergency bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the USAR and are part of the licensing basis for the plant. The offsite circuit from the 345 kV/115 kV Scriba Substation consists of the incoming breaker and disconnect to the respective reserve station service transformers 2RTX-XSR1A and 2RTX-XSR1B and auxiliary boiler transformer 2ABS-X1, the respective 2RTX-XSR1A, 2RTX-XSR1B, and 2ABS-X1 transformers, and the respective circuit path including feeder breakers to all 4.16 kV emergency buses required by LCO 3.8.9.

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective emergency bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 13.20 seconds. The start time includes the 3.20 second Loss of Voltage—Time Delay Function Allowable Value specified in LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation." 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 emergency buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO (continued)	Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. The necessary portions of the Service Water System and Ultimate Heat Sink capable of providing cooling to the required DG(s) are also required. In addition, proper sequencing of loads is a required function for offsite circuit OPERABILITY. It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions.
APPLICABILITY	The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that: a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel; b. Systems needed to mitigate a fuel handling accident are available; c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition. The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.
ACTIONS	LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require

(continued)

BASES

ACTIONS (continued)

immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

A.1

An offsite circuit is considered inoperable if it is not available to one required 4.16 kV emergency bus. If two or more 4.16 kV emergency buses are required per LCO 3.8.9, division(s) with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable that are not powered from offsite power, appropriate restrictions can be implemented in accordance with the required feature(s) LCOs' ACTIONS. Required features remaining powered from a qualified offsite circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable per Required Action A.1. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required AC sources and to

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required emergency bus, ACTIONS for LCO 3.8.9 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for the situation involving a de-energized division.

C.1

When the HPCS System is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS System is not available. Since these sources only affect the HPCS System, the HPCS System is declared inoperable and the Required Actions of LCO 3.5.2, "Emergency Core Cooling Systems—Shutdown" entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.9 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering HPCS System will still perform its function, absent an additional single failure.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3 to be applicable. SR 3.8.1.15 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.18 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude de-energizing a required 4.16 kV emergency bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE. Note 2 states that SRs 3.8.1.10 and 3.8.1.17 are not required to be met when its associated ECCS subsystem(s) are not required to be OPERABLE. These SRs demonstrate the DG response to an ECCS initiation signal (either alone or in conjunction with a loss of offsite power signal). This is consistent with the ECCS instrumentation requirements that do not require the ECCS initiation signals when the associated ECCS subsystem is not required to be OPERABLE per LCO 3.5.2, "ECCS—Shutdown."

REFERENCES

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

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from each storage tank to its respective day tank by two transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. With the exception of certain components (e.g., the fill connections), all outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated locally and is provided with high and low level switches which actuate alarm annunciators in the main control room.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity or absolute specific gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump is sized to contain an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

(continued)

BASES

BACKGROUND (continued)	Each DG has an air start subsystem (that includes two air receivers) with adequate capacity for five successive starts without recharging the air start receivers.
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 6 (Ref. 4) and Chapter 15 and Appendix A (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems. Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of Reference 6.
LCO	Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown." The starting air system is required to have a minimum capacity for five successive DG starts without recharging the air start receivers. Both air start receivers per DG are required to ensure adequate capacity.

(continued)

BASES (continued)

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air subsystems support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

With fuel oil level < 50,000 gallons in a Division 1 or 2 DG storage tank, or < 35,342 gallons in the Division 3 DG storage tank, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

a. Full load operation required after an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

B.1

With lube oil inventory < 99 gallons for a Division 1 or 2 DG or < 168 gallons for the Division 3 DG, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable,

(continued)

BASES

ACTIONS

D.1 (continued)

or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With any starting air receiver pressure < 225 psig for a Division 1 or 2 DG or < 190 psig for the Division 3 DG, sufficient capacity for five successive DG starts does not exist. However, as long as the receiver pressure in both receivers is ≥ 175 psig for a Division 1 or 2 DG and ≥ 110 psig for the Division 3 DG, there is adequate capacity for at least one start, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory (above the manufacturers minimum recommended level) is available to support at least 7 days of full load operation for each DG. The 99 gallon requirement for the Division 1 and 2 DGs and the 168 gallon requirement for the Division 3 DG are based on the DG manufacturer's consumption values for the run time of the DG. The 7 day inventory can be in the engine oil sump or a combination of the engine oil sump and remote storage location. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sumps do not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-81 (Ref. 7);

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 7) that: (1) the sample has an API gravity of within 0.3° at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27 and ≤ 39; (2) a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes; and (3) a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance when tested in accordance with ASTM D4176-82 (Ref. 7).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed within 31 days following addition of the new fuel oil to the fuel oil storage tank(s) to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 7), except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 7) or ASTM D2622-82 (Ref. 7).

The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-78, Method A (Ref. 7). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate concentration is unlikely to change between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine starts without recharging. The pressure specified in this SR is intended to support the lowest value in both receivers at which the five starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of the Surveillance.

REFERENCES

1. USAR, Section 9.5.4.
2. Regulatory Guide 1.137, Revision 1, October 1979.
3. ANSI N195, Appendix B, 1976.
4. USAR, Chapter 6.
5. USAR, Chapter 15 and Appendix A.
6. 10 CFR 50.36(c)(2)(ii).
7. ASTM Standards: D4057-81; D975-81; D4176-82; D1552-79; D2622-82; D2276-78.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of three independent Class 1E DC electrical power subsystems, Divisions 1, 2, and 3. Each subsystem consists of a battery, two 100% capacity battery chargers, and all the associated control equipment and interconnecting cabling.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the batteries.

Each of the Division 1 and 2 electrical power subsystems provides the protection and control power for its associated Class 1E AC power load group, 4.16 kV emergency switchgear, and 600 V load centers. Also, these DC subsystems provide DC electrical power to the associated diesel generator (DG) control panels, DG field flashing, and the emergency uninterruptible power supply (UPS) inverters, which in turn power the 120 VAC uninterruptible panels. In addition, the Division 1 DC electrical power subsystem provides power to the Reactor Core Isolation Cooling System loads. The Division 3 DC electrical power subsystem provides power for High Pressure Core Spray (HPCS) DG field flashing control logic and control and switching function of 4.16 kV Division 3 breakers. It also provides motive and control power for the HPCS System logic, HPCS DG control and protection, and all Division 3 related control.

(continued)

BASES

BACKGROUND (continued)

The DC power distribution system is described in more detail in the Bases for LCO 3.8.8, "Distribution Systems—Operating," and LCO 3.8.9, "Distribution Systems—Shutdown," while a description of the Division 1 and 2 emergency UPS inverters is provided in the Bases for LCO 3.8.7, "Inverters—Operating."

Each Division 1, 2, and 3 battery has adequate storage capacity to carry the required load continuously for at least 2 hours as discussed in the USAR, Section 8.3.2 (Ref. 4).

Each DC battery subsystem is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

The batteries for a DC electrical power subsystem are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The voltage design limit is 1.75 V per cell (Ref. 4).

Each DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 5), and Chapter 15 and Appendix A (Ref. 6), assume that ESF systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC sources satisfy Criterion 3 of Reference 7.

LCO

The DC electrical power subsystems, each subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the divisions, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 4 and 5 and other conditions in which the DC electrical power sources are required are addressed in LCO 3.8.5, "DC Sources—Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

Condition A represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system division.

If one of the required Division 1 or 2 DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable required battery charger, or inoperable required battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1

With the Division 3 DC electrical power subsystem inoperable, the HPCS System may be incapable of performing its intended function and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS—Operating."

C.1 and C.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time specified in Regulatory Guide 1.93 (Ref. 8).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is conservative when compared with the manufacturers recommendations and IEEE-450 (Ref. 9).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each intercell and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The connection resistance limits are ≤ 20% above the resistance as measured during installation (Ref. 9).

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 24 month Frequency for the Surveillance is based on engineering judgement. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of intercell and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

The connection resistance limits are $\leq$ 20% above the resistance as measured during installation (Ref. 9).

The 24 month Frequency for the Surveillance is based on engineering judgment. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

The Surveillance Frequency is acceptable given the administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is acceptable, given unit conditions required to perform the test and the other requirements existing to ensure adequate battery performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test provided the modified performance discharge test completely envelops the service test. This substitution is acceptable because a modified performance discharge test represents a more severe test of battery capacity than SR 3.8.4.7. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is a simulated duty cycle normally consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance discharge test, both of which envelope the duty cycle of the service test. (The test can consist of a single rate if the test rate employed for the performance discharge test exceeds the 1 minute rate.) Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery performance discharge test for the duration of time equal to that of the performance discharge test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a performance discharge test. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 11). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturers rating, since IEEE-485 (Ref. 11) recommends using an aging factor of 125%

(continued)

BASES

SURVEILLANCE

SR 3.8.4.8 (continued)

in the battery size calculation. A capacity of 80% shows that the battery is getting old and capacity will decrease more rapidly, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturers rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturers rating. Degradation is indicated, consistent with IEEE-450 (Ref. 9), when the battery capacity drops by more than 10% of rated capacity in the previous 72 months or when it is below 90% of the manufacturers rating. The 12 month and 60 month Frequencies are consistent with the recommendations in IEEE-450 (Ref. 9). The 24 month Frequency is derived from the recommendations of IEEE-450 (Ref. 9).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, Revision 0, March 10, 1971.
3. IEEE Standard 308, 1974.
4. USAR, Section 8.3.2.
5. USAR, Chapter 6.
6. USAR, Chapter 15 and Appendix A.
7. 10 CFR 50.36(c)(2)(ii).

(continued)

BASES

REFERENCES (continued)	8.	Regulatory Guide 1.93, Revision 0, December 1974.
	9.	IEEE Standard 450, 1980.
	10.	Regulatory Guide 1.32, Revision 2, February 1977.
	11.	IEEE Standard 485, 1978.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources—Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 and Appendix A (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation and during movement of irradiated fuel assemblies in the secondary containment. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that: a. The facility can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident. The DC sources satisfy Criterion 3 of Reference 3.
LCO	The DC electrical power subsystems, each consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated buses within the division, are required to be OPERABLE to support required Distribution System divisions

(continued)

BASES

LCO (continued)	required OPERABLE by LCO 3.8.9, "Distribution Systems—Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).
APPLICABILITY	The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that: a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel; b. Required features needed to mitigate a fuel handling accident are available; c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition. The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.
ACTIONS	LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

(continued)

BASES

ACTIONS (continued)

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If more than one DC distribution subsystem is required according to LCO 3.8.9, the DC electrical power subsystems remaining OPERABLE with one or more DC electrical power subsystems inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with associated DC electrical power subsystem(s) inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. However, in many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8 to be applicable. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1 (continued)

power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15 and Appendix A.
3. 10 CFR 50.36(c)(2)(ii).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 6 (Ref. 1) and Chapter 15 and Appendix A (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit as discussed in the Bases for LCO 3.8.4 and LCO 3.8.5. Since battery cell parameters support the operation of the DC power sources, they satisfy Criterion 3 of Reference 3.
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, these cell parameters are only required when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

(continued)

BASES (continued)

ACTIONS

The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DC electrical power subsystem. Complying with the Required Actions for one inoperable DC electrical power subsystem may allow for continued operation, and subsequent inoperable DC electrical power subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within Table 3.8.6-1 limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell(s) electrolyte level and float voltage are required to be verified to meet Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell(s). One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

7 day intervals until the parameters are restored to Category A and B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the associated DC batteries inoperable.

B.1

When any battery parameter is outside the Table 3.8.6-1 Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as any Required Action of Condition A and associated Completion Time not met or average electrolyte temperature of representative cells ≤ 65°F, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

The SR verifies that Table 3.8.6-1 Category A battery cell parameters are consistent with IEEE-450 (Ref. 4), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte level of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity, voltage, and electrolyte level for each connected cell is consistent with IEEE-450 (Ref. 4). In addition, within 7 days of a battery discharge < 107 V or a battery overcharge > 142 V, the battery must be demonstrated to meet Table 3.8.6-1

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.2 (continued)

Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to < 107 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 4), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge. The 7 day requirement is based on engineering judgement.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is ≥ 65°F is consistent with a recommendation of IEEE-450 (Ref. 4), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. For this SR, a check of 20% of the connected cells is considered representative.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturers recommendations and the battery sizing calculations.

Table 3.8.6-1

This Table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturers recommendations and are consistent with the guidance in IEEE-450 (Ref. 4), with the extra ¼ inch allowance above the high water level indication for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be temporarily above the specified maximum level during and following an equalizing charge (i.e., for up to 3 days following the completion of an equalize charge), provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 4) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on manufacturers recommendations and on the recommendation of IEEE-450 (Ref. 4), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.200 (0.015 below the manufacturers fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 4), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturers recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturers fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturers fully charged, nominal specific gravity). These values are based on manufacturers recommendations. The minimum specific gravity value required for each cell ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for float voltage is based on IEEE-450, Appendix C (Ref. 4), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity (≥ 1.195), is based on manufacturers recommendations (0.020 below the manufacturers recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no more than 0.020 below the average of all connected cells. This limit ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote b requires the above mentioned correction for electrolyte level and temperature.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charging current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 4). Footnote c allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15 and Appendix A.
3. 10 CFR 50.36(c)(2)(ii).
4. IEEE Standard 450, 1980.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters—Operating

BASES

BACKGROUND

The emergency uninterruptible power supply (UPS) inverters are the preferred source of power for the Division 1 and 2 120 VAC uninterruptible electrical power distribution subsystems because of the stability and reliability they achieve. There is one emergency UPS inverter per 120 VAC uninterruptible electrical power distribution subsystem, making a total of two emergency UPS inverters. The function of the emergency UPS inverter is to provide 120 VAC electrical power to the associated uninterruptible panels. The emergency UPS inverter can be powered from an internal AC source/rectifier or from the divisional battery via the associated DC electrical power distribution subsystem. The divisional battery provides an uninterruptible power source for the instrumentation and controls for the Emergency Core Cooling Systems (ECCS) and the loads specified in the VBS Panel Load List.

Specific details on emergency UPS inverters, such as type, capacity, and operating limits, can be found in the USAR, Section 8.3.1.1.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 2) and Chapter 15 and Appendix A (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The emergency UPS inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the ECCS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the emergency UPS inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining electrical power sources OPERABLE during accident conditions in the event of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of Reference 4.

LCO

The emergency UPS inverters ensure the availability of AC electrical power for the instrumentation for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the emergency UPS inverters OPERABLE ensures that the redundancy incorporated into the design of the ECCS instrumentation and controls is maintained. The two battery powered emergency UPS inverters ensure an uninterruptible supply of 120 VAC electrical power to the 120 VAC uninterruptible panels even if the 4.16 kV emergency buses are de-energized.

OPERABLE emergency UPS inverters are required to be aligned to the associated uninterruptible panels, with output voltage and frequency within tolerances, and power input to the emergency UPS inverter from a 125 VDC divisional battery via the associated Class 1E DC bus. Alternatively, power supply may be from an internal AC source/rectifier as long as the divisional battery is available as the uninterruptible power supply.

APPLICABILITY

The emergency UPS inverters 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 AOOs or abnormal transients; and

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

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the emergency UPS inverters are not required to be OPERABLE since, during these MODES, if a loss of offsite power occurred (which could result in loss of power to the uninterruptible panels until the DG starts and energizes the associated emergency buses) coincident with an accident requiring the ECCS instrumentation to perform their function, the response time of the ECCS subsystems (which will be delayed due to the loss of power to the uninterruptible panels) is not as critical.

ACTIONS

A.1

With an emergency UPS inverter inoperable, its associated 120 VAC uninterruptible panels become inoperable until they are re-energized from their Class 1E regulating transformer (maintenance transformer) or emergency UPS inverter using the internal AC source. LCO 3.8.8 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the 120 VAC uninterruptible panels were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.8 must be entered immediately. This ensures the uninterruptible panels are re-energized within 8 hours.

Required Action A.1 allows 24 hours to fix the inoperable emergency UPS inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail. When the 120 VAC uninterruptible panels are powered from their constant voltage maintenance source (or the internal AC source/rectifier with the DC source inoperable), they are relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120 VAC uninterruptible panels is the preferred source for powering instrumentation trip setpoint devices.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable emergency UPS inverter cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the emergency UPS inverters are functioning properly with all required circuit breakers closed and 120 VAC uninterruptible panels energized from the emergency UPS inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the 120 VAC uninterruptible panels. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. USAR, Section 8.3.1.1.2.
2. USAR, Chapter 6.
3. USAR, Chapter 15 and Appendix A.
4. 10 CFR 50.36(c)(2)(ii).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems—Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided by division, for Division 1 and 2, into three independent AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems, and for Division 3, into two independent AC and DC electrical power distribution subsystems.

The primary AC Distribution System consists of three 4.16 kV emergency buses that are supplied from the transmission system by two physically independent circuits. Each 4.16 kV emergency bus also has a dedicated onsite diesel generator (DG) source. The Division 1 and 3 4.16 kV emergency buses are normally supplied by the tertiary winding of reserve station service transformer 2RTX-XSR1A while the Division 2 4.16 kV emergency bus is normally supplied by the tertiary winding of reserve station service transformer 2RTX-XSR1B. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources—Operating," and the Bases for LCO 3.8.4, "DC Sources—Operating."

The secondary plant AC distribution system includes 600 V emergency load centers and associated loads, motor control centers, transformers, and distribution panels.

The Division 1 and 2 120 VAC uninterruptible panels are normally powered from their associated emergency uninterruptible power supply (UPS) inverter. The alternate or maintenance power supply for the uninterruptible panels is a Class 1E regulating transformer powered from the same division as the associated emergency UPS inverter; its use is governed by LCO 3.8.7, "Inverters—Operating." Each regulating transformer is powered from Class 1E AC.

There are three independent 125 VDC electrical power distribution subsystems. The list of required distribution buses is located in Table B 3.8.8-1.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 and Appendix A (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and 120 VAC uninterruptible electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and 120 VAC uninterruptible electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The AC, DC, and 120 VAC uninterruptible electrical power distribution systems satisfy Criterion 3 of Reference 3.

LCO

The required AC, DC, and 120 VAC uninterruptible power distribution subsystems listed in Table B 3.8.8-1 ensure the availability of AC, DC, and 120 VAC uninterruptible electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1, 2, and 3 AC and DC, and Division 1 and 2 120 VAC uninterruptible electrical power primary distribution subsystems are required to be OPERABLE. As noted in Table B 3.8.8-1 (Footnote a), each division of the AC, DC, and 120 VAC uninterruptible electrical power distribution systems is a subsystem.

Maintaining the Division 1, 2, and 3 AC and DC, and Division 1 and 2 120 VAC uninterruptible electrical power

(continued)

BASES

LCO (continued)

distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE 120 VAC uninterruptible electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated emergency UPS inverter via inverted DC voltage, inverter using internal rectified AC source, or Class 1E regulating transformer.

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.8-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.8 is required. Some buses, such as distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.8-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.8-1 (e.g., a breaker supplying a single distribution panel fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.8-1 (e.g., loss of a 4.16 kV emergency bus, which results in de-energization of all buses powered from the 4.16 kV emergency bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since

(continued)

BASES

LCO (continued)

LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV emergency bus).

In addition, tie breakers between Division 1 and Division 2 safety related AC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystems) are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV emergency buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems 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 AOOs or abnormal transients; and

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

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.9, "Distribution Systems—Shutdown."

ACTIONS

A.1

With one or more Division 1 and 2 required AC buses, load centers, motor control centers, or distribution panels (except 120 VAC uninterruptible panels) inoperable and a loss of function has not yet occurred, the remaining AC electrical power distribution subsystems are capable of

(continued)

BASES

ACTIONS

A.1 (continued)

supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this situation, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The low potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition A is entered while, for instance, a DC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.8.a, b, or c, to restore the AC electrical power

(continued)

BASES

ACTIONS

A.1 (continued)

distribution system. At this time, a DC bus could again become inoperable, and the AC electrical power distribution subsystem could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.8.a, b, or c was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.8.a, b, or c indefinitely.

B.1

With one or more Division 1 and 2 120 VAC uninterruptible panels inoperable and a loss of function has not yet occurred, the remaining 120 VAC uninterruptible panels are capable of supporting the minimum safety functions necessary to shut down and maintain the unit in the safe shutdown condition. Overall reliability is reduced, however, because an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the 120 VAC uninterruptible electrical power distribution subsystem(s) must be restored to OPERABLE status within 8 hours by powering the bus from the associated emergency UPS inverter via inverted DC, inverter using internal AC source/rectifier, or Class 1E regulating transformer.

Condition B worst scenario is one 120 VAC uninterruptible electrical power distribution subsystem without power; potentially both the DC source and the associated AC source nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all uninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining 120 VAC uninterruptible electrical power distribution subsystem, and restoring power to the affected 120 VAC uninterruptible electrical power distribution subsystem(s).

This 8 hour limit is more conservative than Completion Times allowed for the majority of components that are without adequate 120 VAC uninterruptible power. Taking exception to

(continued)

BASES

ACTIONS

B.1 (continued)

LCO 3.0.2 for components without adequate 120 VAC uninterruptible power, that would have Required Action Completion Times shorter than 8 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without adequate 120 VAC uninterruptible power, while not providing sufficient time for the operators to perform the necessary evaluations and actions to restore power to the affected division;

c. The potential for an event in conjunction with a single failure of a redundant component.

The 8 hour Completion Time takes into account the importance to safety of restoring the 120 VAC uninterruptible electrical power distribution subsystems to OPERABLE status, the redundant capability afforded by the remaining 120 VAC uninterruptible electrical power distribution subsystems, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition B is entered while, for instance, an AC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 8 hours. This situation could lead to a total duration of 16 hours, since initial failure of LCO 3.8.8.a, b, or c, for restoring the 120 VAC uninterruptible electrical power distribution subsystems. At this time, an AC electrical power distribution subsystem could again become inoperable, and 120 VAC uninterruptible electrical power distribution subsystem could be restored to OPERABLE. This could continue indefinitely.

(continued)

BASES

ACTIONS

B.1 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.8.a, b, or c was initially not met, instead of at the time that Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet LCO 3.8.8.a, b, or c indefinitely.

C.1

With one or more Division 1 and 2 DC buses inoperable and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystem(s) must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C worst scenario is one division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining division, and restoring power to the affected division(s).

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that could be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, that would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

(continued)

BASES

ACTIONS

C.1 (continued)

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 4).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition C is entered while, for instance, an AC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.8.a, b, or c, to restore the DC electrical power distribution system. At this time, an AC electrical power distribution subsystem could again become inoperable, and DC electrical power distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.8.a, b, or c was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet LCO 3.8.8.a, b, or c indefinitely.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

E.1

With the Division 3 electrical power distribution system inoperable (i.e., one or both Division 3 AC and DC electrical power distribution subsystems inoperable), the Division 3 powered systems are not capable of performing their intended functions. Immediately declaring the High Pressure Core Spray System inoperable allows the ACTIONS of LCO 3.5.1, "ECCS—Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost (single division systems are not included, although for this ACTION, Division 3 is considered redundant to Division 1 and 2 ECCS). When two or more inoperable electrical power distribution subsystems result in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC, DC, and 120 VAC uninterruptible electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1 (continued)

appropriate separation and independence of the electrical divisions is maintained, and power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, motor control centers (MCCs), or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable. The 7 day Frequency takes into account the redundant capability of the AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15 and Appendix A.
3. Regulatory Guide 1.93, Revision 0, December 1974.
4. 10 CFR 50.36(c)(2)(ii).

Table B 3.8.8-1 (page 1 of 1)
AC, DC, and 120 VAC Uninterruptible Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a]	DIVISION 3[a]
AC buses	4160 V	Switchgear 2ENS*SWG101	Switchgear 2ENS*SWG103	Switchgear 2ENS*SWG102
	600V	Load Center 2EJS*US1 MCCs 2EHS*MCC101, 2EHS*MCC102, and 2EHS*MCC103 Distribution Panels 2EJS*PNL100A and 2LAC*PNL100A	Load Center 2EJS*US3 MCCs 2EHS*MCC301, 2EHS*MCC302, and 2EHS*MCC303 Distribution Panels 2EJS*PNL300B and 2LAC*PNL300B	MCC 2EHS*MCC201
	240/120 V			Distribution Panel 2SCV*PNL200P
	208/120 V			Distribution Panel 2LAC*PNLE03
DC buses	125 V	Switchgear 2BYS*SWG002A MCC 2DMS*MCCA1 Distribution Panels 2BYS*PNL201A, 2BYS*PNL202A, and 2BYS*PNL204A	Switchgear 2BYS*SWG002B MCC 2DMS*MCCB1 Distribution Panels 2BYS*PNL201B, 2BYS*PNL202B, and 2BYS*PNL204B	Distribution Panel 2CES*IPNL414
120 VAC uninterruptible panels	120 V	Distribution Panels 2VBS*PNL101A and 2VBS*PNL102A	Distribution Panels 2VBS*PNL301B and 2VBS*PNL302B	

(a) Each division of the AC, DC, and 120 VAC uninterruptible electrical power distribution system is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems—Shutdown

BASES

BACKGROUND

A description of the AC, DC, and 120 VAC uninterruptible electrical power distribution systems is provided in the Bases for LCO 3.8.8, "Distribution Systems—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 and Appendix A (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and 120 VAC uninterruptible electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and 120 VAC uninterruptible electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and 120 VAC uninterruptible electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC, DC, and 120 VAC uninterruptible electrical power distribution systems satisfy Criterion 3 of Reference 3.

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications' required systems, equipment, and components—both specifically addressed by their own LCOs, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The AC, DC, and 120 VAC uninterruptible electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.8.

(continued)

BASES (continued)

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal—shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems are functioning properly, with the correct breaker alignment. The correct breaker alignment ensures power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, MCCs, or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Chapter 6.

2. USAR, Chapter 15 and Appendix A.

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

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce unit procedures in preventing the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

GDC 26 of 10 CFR 50, Appendix A, 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, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the position of the refueling platform, the loading of the refueling platform fuel grapple main hoist, and the full insertion of all control rods. Additional inputs are provided for the loading of the refueling platform monorail hoist, the loading of the refueling platform frame-mounted hoist, and the loading of the service platform hoist. With the reactor mode switch in the shutdown or refuel position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment to prevent operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block in the Reactor Manual Control System to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform or any of its hoists are physically located over the reactor vessel. Each hoist load, except the service platform hoist, is sensed by an electronic load

(continued)

BASES

BACKGROUND (continued)

cell. The fuel grapple main hoist load signals are inputs to a programmable logic controller (PLC). The PLC performs the associated interlock and load functions. The monorail and frame-mounted hoist load cells input to electronic setpoint modules that perform their associated interlock and load functions. The PLC opens the associated fuel-loaded circuits at a load lighter than the combined weight of a single fuel assembly and inner-most mast section assembly in water. The electronic setpoint modules open the associated fuel-loaded circuits at a load lighter than the weight of a single fuel assembly in water. The service platform hoist has two switches that also open at a load lighter than the weight of a single fuel assembly in water. The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the USAR analysis of the control rod withdrawal or 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.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core, such that, with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of Reference 4.

(continued)

BASES (continued)

LCO

To prevent criticality during refueling, the refueling interlocks associated with the reactor mode switch refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel-loaded, the refueling platform monorail hoist fuel-loaded, the refueling platform frame-mounted hoist fuel-loaded, and the service platform hoist fuel-loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks when the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode switch is in the shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawals cannot occur simultaneously with in-vessel fuel movements.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

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

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply or is not necessary. This can be performed by ensuring fuel assemblies are not moved in the reactor vessel or by ensuring that the control rods are inserted and cannot be withdrawn. Therefore, Required Action A.1 requires that in-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment

(continued)

BASES

ACTIONS

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

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. Alternately, Required Actions A.2.1 and A.2.2 require that a control rod withdrawal block be inserted and that all control rods are subsequently verified to be fully inserted in core cells containing one or more fuel assemblies. Required Action A.2.1 ensures that no control rods can be withdrawn. This action ensures that control rods cannot be inappropriately withdrawn since an electrical or hydraulic block to control rod withdrawal is in place. Required Action A.2.2 is normally performed after placing the rod withdrawal block in effect and provides a verification that all control rods in core cells containing one or more fuel assemblies are fully inserted. Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure that unacceptable operations are blocked (e.g., loading fuel into a core cell with the control rod withdrawn).

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

2. USAR, Section 7.1.4.

3. USAR, Section 15.4.1.1.

4. 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.

GDC 26 of 10 CFR 50, Appendix A, 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 refuel position one-rod-out interlock is explicitly assumed in the USAR analysis of the control rod withdrawal 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 Reference 4.

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, 4, and 5 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 the refuel position one-rod-out interlock inoperable, the refueling interlocks are not 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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.

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. 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 of 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.

(continued)

BASES (continued)

REFERENCES	1.	10 CFR 50, Appendix A, GDC 26.
	2.	USAR, Section 7.1.4.
	3.	USAR, Section 15.4.1.1.
	4.	10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND

Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation").

GDC 26 of 10 CFR 50, Appendix A, 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 refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis of the control rod withdrawal error during refueling in the USAR (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. Additionally, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality.

Control rod position satisfies Criterion 3 of Reference 3.

(continued)

BASES (continued)

LCO

All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.

APPLICABILITY

During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.

ACTIONS

A.1

With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the USAR. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

The 12 hour Frequency takes into consideration the procedural controls on control rod movement during refueling as well as the redundant functions of the refueling interlocks.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. USAR, Section 15.4.1.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channels for each control rod provide information necessary to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") use the full-in position indication channels to limit the operation of the refueling equipment and the movement of the control rods. Three full-in position indication channels are provided for each control rod (switch S51 and S52 wired in parallel for 00 readout and switch S00, beyond full-in). All three full-in position indication channels provide input to the all-rods-in logic. If any one of the three full-in position indication channels indicates full-in, the all-rods-in logic will receive a full-in signal for that control rod. The absence of all full-in position indication channels signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the selection of any other control rod. The all-rods-in logic provides two signals, one to each of the two Reactor Manual Control System rod block logic circuits.

GDC 26 of 10 CFR 50, Appendix A, 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.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal or removal error during refueling (Ref. 2) assumes the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	functioning of the refueling interlocks and adequate SDM. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time. Control rod position indication satisfies Criterion 3 of Reference 3.
LCO	Each control rod full-in position indication channel for each control rod must be OPERABLE to provide the required inputs to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling equipment interlock all-rods-in logic (LCO 3.9.1) and the refuel position one-rod-out interlock logic (LCO 3.9.2).
APPLICABILITY	During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE. In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.
ACTIONS	A Note has been provided to modify the ACTIONS related to control rod position indication 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 control rod position indication channels provide appropriate compensatory measures for separate inoperable channels. As such, this Note has been provided, which allows separate Condition entry for each inoperable required control rod position indication channel.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies 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. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions may be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicators(s) and to disarm (electrically or hydraulically) the drive(s) to ensure that the control rod is not withdrawn. A control rod can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. A control rod can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are activated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. This is performed by verifying

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1 (continued)

both the absence of a full-in position indication and the absence of an "XX" indication for the control rod on the four control rod group display, when the control rod is not full-in. A full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn from the full-in position is considered adequate because of the procedural controls on control rod withdrawals and the visual indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. USAR, Section 15.4.1.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY—Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

GDC 26 of 10 CFR 50, Appendix A, 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 CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) evaluates the consequences of control rod withdrawal or removal during refueling and also fuel assembly insertion with a control rod withdrawn. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur.

Control rod OPERABILITY during refueling satisfies Criterion 3 of Reference 3.

(continued)

BASES (continued)

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is ≥ 940 psig and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore, are not required to be OPERABLE.

APPLICABILITY

During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

A.1

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures that the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure that a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is ≥ 940 psig.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

The 7 day Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.1.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. USAR, Section 15.4.1.1.
3. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level—Irradiated Fuel

BASES

BACKGROUND

The movement of irradiated fuel assemblies within the RPV requires a minimum water level of 22 ft 3 inches above the top of the RPV flange. During refueling, this maintains a sufficient water level in the reactor vessel cavity and spent fuel storage pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft (Regulatory Position c.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position c.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1), except I-131 which is 12% (Ref. 4).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 22 ft 3 inches (a decontamination factor of 100 is still expected at a water level as low as 22 ft 3 inches) and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 5). While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped assembly, dropping an assembly on the RPV flange will result in reduced releases of fission gases. RPV water level satisfies Criterion 2 of Reference 6.
LCO	A minimum water level of 22 ft 3 inches above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 3.
APPLICABILITY	LCO 3.9.6 is applicable when moving irradiated fuel assemblies within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for handling of new fuel assemblies or control rods (where water depth to the RPV flange is not of concern) are covered by LCO 3.9.7, "RPV Water Level—New Fuel or Control Rods." Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.6, "Spent Fuel Storage Pool Water Level."
ACTIONS	<u>A.1</u> If the water level is < 22 ft 3 inches above the top of the RPV flange, all operations involving movement of irradiated fuel assemblies within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of irradiated fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.9.6.1</u> Verification of a minimum water level of 22 ft 3 inches above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2). The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.
REFERENCES	1. Regulatory Guide 1.25, March 23, 1972. 2. USAR, Section 15.7.4. 3. NUREG-0800, Section 15.7.4. 4. USAR, Table 15.7-9. 5. 10 CFR 100.11. 6. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.7 Reactor Pressure Vessel (RPV) Water Level—New Fuel or Control Rods

BASES

BACKGROUND

The movement of new fuel assemblies or handling of control rods within the RPV when fuel assemblies seated within the reactor vessel are irradiated requires a minimum water level of 22 ft 3 inches above the top of irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level above the irradiated fuel. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During movement of new fuel assemblies or handling of control rods over irradiated fuel assemblies, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1), except I-131 which is 12% (Ref. 4).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 22 ft 3 inches (a decontamination factor of 100 is still expected at a water level as low as 22 ft 3 inches) and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 5). The related assumptions include the worst case dropping of an irradiated fuel assembly onto the reactor core loaded with irradiated fuel assemblies.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RPV water level satisfies Criterion 2 of Reference 6.
LCO	A minimum water level of 22 ft 3 inches above the top of irradiated fuel assemblies seated within the RPV is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 3.
APPLICABILITY	LCO 3.9.7 is applicable when moving new fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) when irradiated fuel assemblies are seated within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.6, "Spent Fuel Storage Pool Water Level." Requirements for handling irradiated fuel over the RPV are covered by LCO 3.9.6, "Reactor Pressure Vessel (RPV) Water Level—Irradiated Fuel."
ACTIONS	<u>A.1</u> If the water level is < 22 ft 3 inches above the top of irradiated fuel assemblies seated within the RPV, all operations involving movement of new fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.7.1</u> Verification of a minimum water level of 22 ft 3 inches above the top of the irradiated fuel assemblies seated within the RPV ensures that the design basis for the postulated fuel handling accident analysis during refueling

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1 (continued)

operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
2. USAR, Section 15.7.4.
3. NUREG-0800, Section 15.7.4.
4. USAR, Table 15.7-9.
5. 10 CFR 100.11.
6. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR)—High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Service Water (SW) System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR System satisfies Criterion 4 of Reference 2.

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE and in operation in MODE 5 with irradiated fuel in the RPV and the water level ≥ 22 ft 3 inches above the RPV flange. Only one subsystem is required to be OPERABLE because the volume of water above the RPV flange provides backup decay heat removal capability.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the heat exchanger and the RHR pump seal cooler, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

(continued)

BASES

LCO (continued)

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation every 8 hours. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystem or other operations requiring RHR flow interruption.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE and in operation in MODE 5, with irradiated fuel in the RPV and with the water level ≥ 22 ft 3 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5, with irradiated fuel in the RPV and with the water level < 22 ft 3 inches above the RPV flange, are given in LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be provided within 1 hour. In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of the alternate method must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit operating procedures. The required cooling capacity of the alternate

(continued)

BASES

ACTIONS

A.1 (continued)

method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. For example, this may include the use of the Spent Fuel Pool Cooling and Cleanup System, Alternate Decay Heat Removal System, or the Reactor Water Cleanup System operating with the regenerative heat exchanger bypassed or in combination with the Control Rod Drive System or Condensate/Feed System. The method used to remove the decay heat should be the most prudent choice based on unit conditions.

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

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend operations involving an increase in reactor decay heat load by suspending the loading of irradiated fuel assemblies into the RPV.

Additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE, one standby gas treatment subsystem is OPERABLE, and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated). This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it

(continued)

BASES

ACTIONS

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

must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This Surveillance demonstrates that the required RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR shutdown cooling subsystem in the control room.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 34.
2. 10 CFR 50.36(c)(2)(ii).

B 3.9 REFUELING OPERATIONS

B 3.9.9 Residual Heat Removal (RHR)—Low Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the Service Water (SW) System. The RHR shutdown cooling mode is manually controlled.
APPLICABLE SAFETY ANALYSES	With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant. The RHR System satisfies Criterion 4 of Reference 2.
LCO	In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level < 22 ft 3 inches above the RPV flange both RHR shutdown cooling subsystems must be OPERABLE and one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the heat exchanger and the RHR pump seal cooler, valves, piping, instruments, and controls to ensure an OPERABLE flow path. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant

(continued)

BASES

LCO (continued)

temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation every 8 hours. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystem or other operations requiring RHR flow interruption.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE and one RHR shutdown cooling subsystem must be in operation in MODE 5, with irradiated fuel in the RPV and with the water level < 22 ft 3 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5, with irradiated fuel in the RPV and the water level ≥ 22 ft 3 inches above the RPV flange, are given in LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level."

ACTIONS

A.1

With one of the two RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

(continued)

BASES

ACTIONS

A.1 (continued)

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit operating procedures. The required cooling capacity of the alternate method(s) should be ensured by verifying (by calculation or demonstration) their capability to maintain or reduce temperature. For example, this may include the use of the Spent Fuel Pool Cooling and Cleanup System, Alternate Decay Heat Removal System, or the Reactor Water Cleanup System operating with the regenerative heat exchanger bypassed or in combination with the Control Rod Drive System or Condensate/Feed System. The method used to remove decay heat should be the most prudent choice based on unit conditions.

Condition A is modified by a Note allowing separate Condition entry for each inoperable RHR shutdown cooling subsystem. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each inoperable RHR shutdown cooling subsystem. Complying with the Required Actions allow for continued operation. A subsequent inoperable RHR shutdown cooling subsystem is governed by subsequent entry into the Condition and application of the Required Actions.

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

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE, one standby gas treatment subsystem is OPERABLE, and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a

(continued)

BASES

ACTIONS

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

need for secondary containment isolation is indicated). This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.9.9.1

This Surveillance demonstrates that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR shutdown cooling subsystem in the control room.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 34.
2. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.1 System Leakage and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3).

Hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation, decay heat, and a water solid RPV (except for a gas bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases for a given pressure. Periodic updates to the RCS P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and system leakage testing will eventually be required with minimum reactor coolant temperatures > 200°F.

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4 during hydrostatic or system leakage testing, when the reactor coolant temperature is > 200°F, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the hydrostatic or system leakage tests are performed nearly water solid (except for a gas bubble for pressure control), at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.8, "Reactor Coolant System (RCS) Specific Activity," are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or system leakage testing. The required pressure testing conditions specified in the USAR (e.g., average reactor coolant temperature ≤ 212°F) provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the ECCS to operate. The capability of the low pressure coolant injection, low pressure core spray, and high pressure core spray subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS—Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic and system leakage test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 3 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 200°F, can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures

(continued)

BASES

LCO (continued)	> 200°F, while performance of system leakage and hydrostatic testing results in inoperability of subsystems required when > 200°F (i.e., MODE 3). If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purposes of performing either a system leakage or hydrostatic test. This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation.
APPLICABILITY	The MODE 4 requirements may only be modified for the performance of system leakage or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 200°F. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.
ACTIONS	A Note has been provided to modify the ACTIONS related to system leakage and hydrostatic testing operation. Section 1.3, Completion Times, specifies 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 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS (continued)

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements shall be entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to ≤ 200°F.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operations LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to ≤ 200°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 for reaching MODE 4 from MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

REFERENCES

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.
2. USAR, Section 15.6.4.
3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown—Initiates a reactor scram; bypasses main steam line isolation scram;

b. Refuel—Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation scram;

c. Startup/Hot Standby—Selects NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation scram; and

d. Run—Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The purpose for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality.

The interlock functions of the shutdown and refuel positions of the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, or startup/hot standby) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore no criteria of Reference 3 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "System Leakage and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," and LCO 3.10.8, "SDM Test—Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified

(continued)

BASES

LCO (continued)

fully inserted while in MODES 3, 4, and 5 with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

In MODE 5, with the reactor mode switch in the refuel position, only one control rod can be withdrawn under the refuel position one rod out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed without this allowance or testing that must be performed prior to entering another MODE. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

(continued)

BASES

ACTIONS

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

All CORE ALTERATIONS, except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. 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. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control rods remain inserted and result in operation in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. In addition, the all rods fully inserted Surveillance (SR 3.10.2.1) must be verified by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.2.1 and SR 3.10.2.2 (continued) shift technical advisor or reactor engineer). The Surveillances performed at the 12 hour and 24 hour Frequencies are intended to provide appropriate assurance that each operating shift is aware of and verify compliance with these Special Operations LCO requirements.
REFERENCES	1. USAR, Section 7.2. 2. USAR, Section 15.4.1.1. 3. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal—Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of an accident. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing" without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn.

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

(continued)

BASES (continued)

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication") full insertion requirements for all other control rods, and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.3, "Reactor Protection System (RPS) Electric Power Monitoring—Scram Solenoids," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative control in Item d.2 of this Special Operations LCO, minimizes potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies 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 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. This Required Action has been modified by a Note that clarifies the intent of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations Applicability LCO by returning the reactor mode

(continued)

BASES

ACTIONS

A.1 (continued)

switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 and are alternative Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks that preclude additional control rod withdrawals.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 15.4.1.1.
2. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal—Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of an accident. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing the CRD because this removal renders the withdrawn control rod incapable of being scrammed. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained. To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable

(continued)

BASES

LCO (continued)

of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring—Logic," LCO 3.3.8.3, "Reactor Protection System (RPS) Electric Power Monitoring—Scram Solenoids," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. Section 1.3, Completion Times, specifies 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS (continued)

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations LCO Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the shutdown position. Action must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must immediately be suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or restore compliance with this Special Operations LCO.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. USAR, Section 15.4.1.1.

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

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod, in a core cell containing one or more fuel assemblies, is permitted to be withdrawn. The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY—Refueling").

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of accidents. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn, and all other control rods are inserted and incapable of being withdrawn by insertion of a control rod block.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

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BASES (continued)

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs—LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring—Logic," LCO 3.3.8.3, "Reactor Protection System (RPS) Electric Power Monitoring—Scram Solenoids," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5—not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.3.8.3, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all-rods-in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.3.8.3, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduces the potential for reactivity excursions.

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BASES (continued)

ACTIONS

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

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods other than the control rod withdrawn for the removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5 (continued)

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on control rod removal and hardware interlocks to block an additional control rod withdrawal.

REFERENCES

1. USAR, Section 15.4.1.1.
2. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational 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 from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rods may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full-in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the USAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full-in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from

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BASES

APPLICABLE SAFETY ANALYSES (continued)	the cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY—Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. When loading fuel into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Spiral reloading encompasses reloading a cell (four fuel locations immediately adjacent to a control rod) on the edge of a continuous fueled region (the cell can be loaded in any sequence). Otherwise, all control rods must be fully inserted before loading fuel.

(continued)

BASES (continued)

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2, Required Action A.3.1, and Required Action A.3.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.

REFERENCES

1. USAR, Section 15.4.1.1.
2. 10 CFR 50.36(c)(2)(ii).

B 3.10 Special Operations

B 3.10.7 Control Rod Testing—Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RWM. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a control rod drop accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests may include SDM demonstrations, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exceptions to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in Reference 1. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analysis of Reference 1 may not be preserved. Therefore, special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurance that the test sequence is followed can be provided by either programming the test sequence into the RWM with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."
APPLICABILITY	Control rod testing, while in MODES 1 and 2 with THERMAL POWER greater than 10% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed control rod sequences of LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in

(continued)

BASES

APPLICABILITY (continued)

accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown" or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 1 are satisfied. During these Special Operations and while in MODE 5, the one rod out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock) and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, minimize potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern not in compliance with the special test sequence, the sequence is improperly loaded in the RWM), the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken either to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

With the special test sequence not programmed into the RWM, a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer) is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be met if SR 3.10.7.2 is satisfied.

SR 3.10.7.2

When the RWM provides conformance to the special test sequence, the test sequence must be verified to be correctly loaded into the RWM prior to control rod movement. This

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.7.2 (continued) Surveillance demonstrates compliance with SR 3.3.2.1.8, thereby demonstrating that the RWM is OPERABLE. A Note has been added to indicate that this Surveillance does not need to be met if SR 3.10.7.1 is satisfied.
REFERENCES	1. USAR Section 15.4.9. 2. 10 CFR 50.36(c)(2)(ii).

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup/hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup/hot standby position while in MODE 5, is provided by the Intermediate Range Monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analysis of Reference 1 is applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analysis of Reference 1 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analysis (Ref. 1). In addition to the added requirements for the rod worth minimizer (RWM), APRM, and control rod coupling, the single notch withdrawal mode is specified for out of sequence withdrawals. Requiring the single notch withdrawal mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of Reference 2 apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2.a, 2.d, and 2.e) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence

(continued)

BASES

LCO (continued)

must be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2), or must be verified by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in LCO 3.1.6, "Rod Pattern Control" (i.e., out of sequence control rod withdrawals) must be made in the notched withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since, if the control rod fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling

(continued)

BASES

ACTIONS

A.1 (continued)

is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 ACTIONS provide additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a, 2.d, and 2.e, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met (SR 3.10.8.1). However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2 requirements) or by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff (e.g., a qualified shift technical advisor or reactor engineer). As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These Surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed any time a control rod is withdrawn to the "full-out" notch position or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. Since the reactor is depressurized in MODE 5, there is insufficient reactor pressure to scram the control rods. Verification of charging water header pressure ensures that if a scram were required, capability for rapid control rod insertion would exist. The minimum pressure of 940 psig is well below the expected pressure of 1050 psig to 1100 psig while still ensuring sufficient pressure for rapid control rod insertion. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. USAR Section 15.4.9.
2. 10 CFR 50.36(c)(2)(ii).