B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Coolant Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes more heat 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 Coolant 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 one variable speed motor driven recirculation pump, a Motor Generator (MG) set to control pump speed and 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. 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. The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat

(continued)

BASES

BACKGROUND (continued)

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% of 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 MG set provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled by varying the speed of the corresponding recirculation pump.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Coolant 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. 1). 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the loop with the higher flow. While the flow coastdown and 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. Since recirculation loop flow is controlled by varying recirculation pump speed, a limit on the speed mismatch between operating recirculation pumps has been imposed. For some limited low probability accidents (e.g., intermediate break size LOCAs) with the recirculation loop operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions the Core Spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, operating procedures have been put into place limiting the allowable mismatch in speed between the recirculation pumps.

Analyses indicate that above 80% RTP the Loop Select Logic could be expected to function at a speed differential up to 14% of their average speed. Below 80% RTP the Loop Select Logic would be expected to function at a speed differential up to 20% of their average speed. The recirculation loop speed mismatch limits imposed to prevent the LPCI Loop Select Logic from selecting the wrong loop for injection bound the recirculation flow mismatch limits for LOCA analyses. If the reactor is operating on one recirculation pump, the Loop Select Logic trips that pump before making the loop selection.

The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the UFSAR.

A plant specific LOCA analysis has been performed assuming only Single Loop Operation (SLO). 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. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The transient analyses of Chapter 15 of the UFSAR have also been performed for SLO (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During SLO, modification to the Reactor Protection System (RPS) Average Power Range Monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR setpoints for SLO are specified in the COLR. The APRM Flow Biased High Scram allowable value is in LCO 3.3.1.1, "Reactor Protection System (RPS)Instrumentation."

Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Two recirculation loops are normally required to be in operation with the recirculation pump speeds matched within the limits specified in SR 3.4.1.1 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. Alternately, 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 RATIO (MCPR)"), and APRM Flow Biased High Scram allowable value (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of Reference 3. The idle loop is isolated electrically by disconnecting the breaker to the recirculation pump motor generator (M/G) set drive motor prior to reactor startup or, if disabled during reactor operation, within 24 hours of entering SLO. With either one or two recirculation pumps in operation, core flow as a function of THERMAL POWER must be outside the Exclusion Region specified in the COLR to avoid the potential for thermal hydraulic instability.

(continued)

BASES (continued)

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

With no recirculation loops in operation, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor mode switch must be placed in the Shutdown position Immediately. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown position is permitted by the definition of an Immediate Completion Time. Operation in natural circulation could place the plant in or near the Exclusion Region for thermal hydraulic instability. Manually scramming the reactor is the recommended method of exiting the Exclusion Region when the plant is operating in natural circulation, since restarting a recirculation pump in this condition could result in the initiation of thermal hydraulic instability.

B.1

With one or two recirculation loops in operation in the Exclusion Region of the power/flow map, immediate action must be initiated to exit the Exclusion Region. This action can be to insert control rods or to increase core flow. Entries into the Exclusion Region are not part of normal operation. An entry may occur as a result of an abnormal event, such as a single recirculation pump trip. In these events, operation in the Exclusion Region may be needed to prevent equipment damage, but actual time spent inside the Exclusion Region is minimized.

(continued)

BASES (continued)

ACTIONS

B.1 (continued)

Though each operator action can prevent the occurrence and protect the reactor from an instability, the APRM flow-biased scram function is designed to suppress global oscillations, the most likely mode of oscillation, prior to exceeding the fuel safety limit (Ref. 4). While global oscillations are the most likely mode, protection from out-of-phase oscillations are provided through avoidance of the Exclusion Region and administrative controls on reactor conditions which are primary factors affecting reactor stability.

C.1

If recirculation pump speed mismatch is not within limits, the pump speed mismatch must be restored or one recirculation pump must be tripped within two hours. For some limited low probability accidents with the recirculation loops operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions, Core Spray itself is adequate to prevent fuel temperature from exceeding allowable limits. However, to limit the probability even further, a two hour Completion Time has been established. The two hour Completion Time provides a reasonable time for the operator to restore the pump speed mismatch to within limits.

D.1

With the requirements of the LCO not met for reasons other than Conditions A, B, or C, the Single Loop Operation (SLO) limits must be applied for LCO 3.2.1, "AVERAGE PLANER LINEAR HEAT GENERATION RATE (APLHGR), "LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." Should a LOCA occur with one recirculation loop not in operation when the limits specified for SLO have not been applied, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to apply the limits specified for SLO or restore the inoperable loop to operating status.

(continued)

BASES (continued)

ACTIONS

D.1 (continued)

Alternatively, if the limits specified for SLO are applied, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence and transient analysis.

The 24 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the necessary SRs to meet the requirements of the LCO and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

E.1

With the Required Action and associated Completion Time of Condition C, or D 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 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for speed mismatch. For some limited low probability accidents with the recirculation loop operating with large speed differences, it is possible for the LPCI Loop Select Logic to select the wrong loop for injection. For these limited conditions, Core Spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, a limitation has been placed on the allowable variation in speed between the recirculation pumps.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

Analyses indicate that above 80% RTP the LPCI Loop Select Logic could be expected to function at a speed differential up to 14% of average recirculation pump speed with the specification limit set at approximately ± 10% of average recirculation pump speed to provide margin. Below 80% RTP the Loop Select Logic would be expected to function at a speed differential up to 20% of average recirculation pump speed with the specification limit set at approximately ± 15% of average recirculation pump speed to provide margin. If the reactor is operating on one recirculation pump, the Loop Select Logic trips the pump before making the loop selection. The mismatch is measured in terms of percent of the speed of one recirculation pump compared to the speed of the other recirculation pump. If the speed mismatch exceeds the specified limits and cannot be restored within two hours, one recirculation pump shall be tripped. The SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Surveillance 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. This SR ensures the reactor THERMAL POWER and core flow are within appropriate parameter limits to prevent uncontrolled power oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal hydraulic instability if operation is permitted in the Exclusion Region shown in the Core Operating Limits Report. The 24 hour Frequency is based on operating experience and the operators' inherent knowledge of reactor status, including significant changes in THERMAL POWER and core flow.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.4.3.3.

2. UFSAR, Section 15.3.

3. NEDO-24272, Duane Arnold Energy Center Single-Loop Operation, Supplemented by DAEC Supplement to NEDC-32915P, "Duane Arnold Energy Center GE12 Fuel Upgrade Project", APED L12-003, March 2000.

4. NEDC-32915P, "Duane Arnold Energy Center GE12 Fuel Upgrade Project", November 1999.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Coolant 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 Coolant 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 eight 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 2 of 10 CFR 50.36(c)(2)(ii).

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 Coolant 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 Coolant Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Coolant 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 of reflooding 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 Completion Time of 12 hours is

(continued)

BASES

ACTIONS

A.1 (continued)

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 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). 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 the 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. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided; i.e., meeting criterion a means that data collection required for evaluation against criterion b is unnecessary. In addition, when recirculation pump speeds are less than 60% of rated, criterion c allows an engineering evaluation to be performed to determine that the criteria a and b data are acceptable. 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 base-lining 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 pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally 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 flow (or 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. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by three Notes. Notes 1 and 2 affect the entire SR. The third Note only affects criterion c. 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 when THERMAL POWER is ≤ 25% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

instrumentation and precludes the collection of repeatable and meaningful data.

Note 3 allows criterion c to be applied when recirculation pump speed is ≤ 60% of rated speed. Criterion c allows engineering judgment to be applied to an evaluation of the data collected for criteria a and b, to determine if the data is acceptable. This evaluation can take into account factors such as the influence of instrument accuracy and natural circulation at core flows less than 50% of rated. This data should be collected and evaluated every 24 hours when recirculation pump speeds are ≤ 60% of rated. If multiple data points are collected at pump speeds ≤ 60%, the trend of such data should be evaluated for acceptability. When this data is collected with recirculation pump speeds > 60% of rated, criteria a or b limits must always be met.

REFERENCES

1. UFSAR, Section 6.3.
2. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Bean Cracks," June 9, 1980.
3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety Relief Valves (SRVs) and Safety Valves (SVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code 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 SRVs and SVs 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 SRVs and SVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The SRVs can actuate by either of two modes: the safety mode or the relief mode. However, for the purpose of this LCO, only the safety mode is required. The SVs actuate only in the safety mode. In the safety mode (or spring mode of operation), the spring loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. The safety mode function of both SRVs and SVs satisfies the Code requirement. A power generation design basis function of the SRVs is also to prevent opening of the SVs during normal plant isolations and load rejections.

Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool while the SVs discharge directly to the drywell airspace. The SRVs that provide the relief mode are the Low-Low Set (LLS) valves and the Automatic Depressurization System (ADS) valves. The LLS requirements are specified in LCO 3.6.1.5, "Low-Low Set (LLS) Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS-Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization 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 associated with MSIV position) (Ref. 1). For the purpose of the analyses, 6 valves (any combination of SRVs

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

and SVs) are assumed to operate in the safety mode. The analysis results demonstrate that the design SRV and SV 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 Design Basis Event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the SRVs.

SRVs and SVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The safety function of 8 valves; (SRVs and SVs) is available; however, to satisfy the assumptions of the safety analysis, only 6 valves (any combination of SRVs and SVs) are required to be OPERABLE (Refs. 1 and 2). All eight valves are specifed to be OPERABLE so that the reactor will not be operated for an unlimited period of time with any one valve inoperable. The requirements of this LCO are applicable only to the capability of the SRVs and SVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

The SRV and SV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for over pressurization conditions. The transient evaluations in the UFSAR are based on these setpoints, but also include the additional uncertainties of a 1% (high) error in the nominal setpoint 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, all SRVs and SVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The SRVs and SVs may be required to provide pressure relief to discharge energy from the core so that the Residual Heat Removal(RHR) System is capable of dissipating the core heat via either the Suppression Pool Cooling mode or the Shutdown Cooling mode.

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 SRV and SV function is not needed during these conditions.

ACTIONS

A.1

With the safety function of one SRV or SV inoperable, the remaining OPERABLE SRVs or SVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with any combination of two SRVs or SVs inoperable. However, the overall reliability of pressure relief system is reduced because additional failures in the remaining OPERABLE SRVs or SVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

The 30 day Completion Time to restore the inoperable SRVs or SVs to OPERABLE status is based on the relief capability of the remaining SRVs and SVs, the low probability of an event requiring SRV and SV actuation, and that single failure criterion is retained.

(continued)

BASES

ACTIONS (continued)

B.1

With the safety function of any combination of two SRVs or SVs inoperable, the remaining OPERABLE SRVs and SVs are capable of providing the necessary overpressure protection: however, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE SRVs or SVs could result in failure to adequately relieve pressure during a limiting event. Therefore, a more restrictive Completion Time is specified.

The 7 day Completion Time to restore at least one inoperable valve to OPERABLE status takes into account the low probability of an event requiring SRV and SV actuation, coupled with an additional single failure of an SRV or SV where the relief capability would be inadequate. The 7 Day Completion Time is consistent with other requirements where a loss of redundancy has occurred.

C.1 and C.2

With less than the minimum number of required SRVs and SVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of the inoperable SRVs OR SVs cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1 or B.1 or if the safety function of any combination of three or more SRVs or SVs is 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 and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the SRVs and SVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the SRV and SV lift settings must be performed during shutdown, since this is a bench test, to be done 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 SRV and SV setpoints are ± 3% for OPERABILITY; however the valves are reset to ± 1% during the Surveillance to allow for drift.

The Surveillance Frequency is in accordance with the Inservice Testing Program requirements contained in the ASME Code, Section XI. This Surveillance must be performed during shutdown conditions.

SR 3.4.3.2

A manual actuation of each SRV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control valves or bypass valves, by a change in the measured steam flow by pressure switches and thermocouple readings downstream of the SRV indicating steam flow, or by any other method suitable to verify steam flow. 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 SRVs 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 approximately 150 psig which is the lowest pressure EHC can maintain. Adequate steam flow is represented by approximately 1.15 turbine bypass valves open. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.2 (continued)

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. If a valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the SRV is not considered inoperable.

This SR is not applicable to the SVs, due to their design which does not include the manual relief capability, nor do they have a discharge line that can become blocked.

The 24 month Surveillance Frequency is consistent with the guidance of NUREG 1482, part 4.3.4 (Ref. 4), where the staff recommends reducing the number of challenges to dual function relief valves, because failure in the open position is equivalent to a small break LOCA. 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.

REFERENCES

1. UFSAR, Section 5.2.2.2.
2. UFSAR, Section 15.2.
3. ASME, Boiler and Pressure Vessel Code, Section XI.
4. NUREG 1482, Guidelines for Inservice Testing at Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 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 UFSAR Section 3.1.2.4.1 (Ref. 1).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment 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 that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection. Note that RCS LEAKAGE does not include weepage through SRVs into the Suppression Pool, since the weepage is not into the primary containment atmosphere and is not quantifiable.

This LCO deals with protection of both 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

(continued)

BASES

BACKGROUND (continued)	of violating this LCO include the possibility of a Loss of Coolant Accident.

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 that, 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. 2 and 3) shows that leakage rates significantly higher than the allowed LEAKAGE will precede crack instability (Ref. 4).

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 total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Unidentified LEAKAGE

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the

(continued)

BASES

LCO

a. Unidentified LEAKAGE (continued)

Primary Containment Air Sampling System and Drywell Sump System can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

b. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also 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.

c. 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 total 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 total 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. The increase does not necessarily violate the absolute unidentified LEAKAGE limit, therefore, an option exists to allow continued reactor operation if certain susceptible components are 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 evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type piping is very susceptible to IGSCC. Note also that once LEAKAGE is attributed to a specific source, that LEAKAGE can be considered to be identified and can be applied against the identified limit, rather than the unidentified limit.

The 4 hour Completion Time is reasonable to properly reduce the unidentified LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

(continued)

BASES (continued)

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is 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 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 safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

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 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, other methods may be used to quantify LEAKAGE within the guidelines of Reference 5. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 5).

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 3.1.2.4.1.

2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.

3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.

4. UFSAR, Section 5.2.5.3.2.

5. Generic Letter 88-01, Supplement 1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR Section 3.1.2.4.1 (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

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. 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 leakage rates. The Bases for LCO 3.4.4, "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 various independently monitored variables, such as sump level changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the Drywell Sump System.

The Drywell Sump System monitors the LEAKAGE collected in the floor drain sump and the equipment drain sump. The unidentified LEAKAGE is collected in the floor drain sump and consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The identified LEAKAGE is collected in the equipment drain sump and consists of LEAKAGE from various expected LEAKAGE sources. Both the drywell floor drain sump and the drywell equipment drain sump have transmitters that supply level indications in the reactor building.

Both the floor drain sump and equipment drain sump level indicators have switches that start and stop the sump pumps when required. A sump fill timer starts each time either sump is pumped down to the low level setpoint.

(continued)

BASES

BACKGROUND (continued)

If either sump fills to the high level setpoint before the sump fill timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit.

Both the floor drain sump and equipment drain sump also have a sump pump out timer which measures the time from automatic or manual initiation of the pump to the low level setpoint. The time of pump operation is converted to a leakage rate. An alarm annunciates in the control room if the leakage rate exceeds a preset limit.

The flow indicators in the discharge lines of the drywell floor drain sump pumps and drywell equipment drain sump pumps provide flow indications in the control room. The pumps can also be started from the control room.

The equipment drain sump subsystem instrumentation consists of one equipment drain sump flow integrator, the equipment drain sump fill timer and the equipment drain sump pump out timer. The floor drain sump subsystem instrumentation likewise consists of one floor drain sump flow integrator, the floor drain sump fill timer and the floor drain sump pump out timer. The Drywell Sump System is OPERABLE when any one of these six devices is OPERABLE, with its associated sump pump capable of pumping. Examples of situations where the pumps will not start are loss of power to 1C-84 and failure of the sump pump level switches. If system flow is prohibited, such as by the closure of an isolation valve, the pumps won't pump and the system is not OPERABLE because it cannot perform its specified safety function.

The Primary Containment Air Sampling System continuously monitors the primary containment atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity may be attributed to RCPB steam or reactor water LEAKAGE. The Primary Containment Air Sampling System is not capable of quantifying LEAKAGE rates, but is sensitive enough to indicate increased LEAKAGE rates.

The Primary Containment Air Sampling System provides a backup system to the Drywell Sump System. The Primary Containment Air Sampling System consists of six channels (two gaseous, two Iodine, and two particulate). The Primary Containment Air Sampling System is OPERABLE when any one of the six available channels is OPERABLE.

(continued)

BASES (continued)

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. 2 and 3). 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. 4).

Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

The Drywell Sump System is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE. An alternate to the drywell floor drain sump subsystem is the drywell equipment drain sump subsystem, but only if the drywell floor drain sump is overflowing. If the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump subsystem can be used to quantify LEAKAGE. In this condition, all LEAKAGE measured by the drywell equipment drain sump subsystem is assumed to be unidentified LEAKAGE. The other monitoring systems provide additional indication 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. The Primary Containment Air Sampling System provides a backup system to the Drywell Sump System. The Primary Containment Air Sampling System is OPERABLE when any one of the six available channels is OPERABLE. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

ACTIONS

A.1

With the Drywell Sump System inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the Primary Containment Air Sampling System will provide indication of changes in leakage.

With the Drywell Sump System inoperable, operation may continue for 24 hours. The 24 hour Completion Time is acceptable, based on operating experience, considering no other method to quantify leakage is 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 Sump System is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

B.1

With all six gaseous and particulate Primary Containment Air Sampling System channels inoperable, action to restore the required Primary Containment Air Sampling System to OPERABLE status is required immediately. This is allowed because leakage can still be quantified by the Drywell Sump System.

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 all six gaseous and particulate Primary Containment Air Sampling System channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

C.1 and C.2

With all six gaseous and particulate Primary Containment Air Sampling System channels and the Drywell Sump System inoperable, no means of detecting LEAKAGE is available. This condition does not provide the required diverse means

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

of leakage detection. The Required Action is to restore either of the inoperable monitoring systems to OPERABLE status within 4 hours to regain the intended leakage detection diversity. The 4 hour Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

D.1 and D.2

If any Required Action of Condition A or C cannot be met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required Primary Containment Air Sampling 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 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator and floor drain sump flow integrator. The CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of at least one contact on the relay which inputs into the trip logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the CHANNEL CALIBRATION. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the CHANNEL CALIBRATION. These tests ensure that the monitors can

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

perform their function in the desired manner and also verifies the Primary Containment Air Sampling System alarm functions properly. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.5.3

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of required equipment drain sump fill and sump pump out timers and floor drain sump fill and sump pump out timers. The CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of at least one contact on the relay which inputs into the trip logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the CHANNEL CALIBRATION. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the CHANNEL CALIBRATION. The Frequency of 92 days considers channel reliability. Operating experience has proven this Frequency is acceptable.

SR 3.4.5.4 and SR 3.4.5.5

These SRs are for the performance of a CHANNEL CALIBRATION of required Primary Containment Air Sampling System instrumentation, equipment drain sump flow integrator, floor drain sump flow integrator, equipment drain sump fill and sump pump out timers and floor drain sump fill and sump pump out timers. The calibration verifies the accuracy of the instrument string, excluding the level elements located inside containment. The level elements have no adjustable parts and thus, do not require calibration. The Frequency of 92 days or 12 months considers channel reliability. Operating experience has proven these Frequencies are acceptable.

REFERENCES

1. UFSAR Section 3.1.2.4.1.
2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactors," October 1975.
4. UFSAR, Section 5.2.5.2.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND

During circulation in normal operating conditions, the reactor coolant acquires radioactive materials due to release of fission products from "tramp" uranium on the outside of the fuel cladding and activation of corrosion products in the reactor coolant. There is the potential for fuel leaks into the reactor coolant that will contribute to the level of radioactive materials due to release of fission products. These radioactive materials in the reactor 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 that 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 milliliter 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 UFSAR (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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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. 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 10 CFR 50.36(c)(2)(ii).
LCO	The specific iodine activity is limited to ≤ 1.2 μCi/ml 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 ≤ 12.0 μCi/ml, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 1.2 μCi/ml within 48 hours, or if at any time it is > 12.0 μCi/ml, it must be determined at least once every 4 hours and all the main steam lines, including the main steam line drains, must be isolated within 12 hours. Isolating the main steam lines including drains, 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.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in 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

(continued)

BASES

ACTIONS

B.1, B.2.1, B.2.2.1, and B.2.2.2 (continued)

challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 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

This Surveillance is performed to ensure iodine remains within limit during normal operation. The analysis is performed using filtrate from a 0.45μ filter. 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, 1973.

2. UFSAR, Sections 15.6.5 and 15.10.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 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 ≤ 212°F. This decay heat is removed in preparation for performing Refueling or Cold Shutdown maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling loops of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, 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 RHR Service Water System (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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 function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

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. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both pumps and a heat exchanger in one loop or one pump and an

(continued)

BASES

LCO (continued)

associated heat exchanger in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Thus, two RHR pumps in a common RHR subsystem, together with the associated heat exchanger and flow path components, constitutes two OPERABLE RHR shutdown cooling subsystems. 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 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 of one RHR shutdown cooling subsystem is required.

Note 1 permits both required RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one required RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the 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 RCIC Steam Supply Line Pressure - Low isolation pressure the RHR System must be OPERABLE and 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 RCIC Steam Supply Line Pressure - Low isolation pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above the RHR shutdown cooling isolation interlock pressure (which is

(continued)

BASES

APPLICABILITY (continued)

slightly higher than the RCIC Steam Supply Line Pressure - Low isolation 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 RCIC Steam Supply Line Pressure - Low isolation pressure is typically accomplished by condensing the steam in the main condenser. Providing this operational overlap between the different pressures allows a smooth transition between these methods of decay heat removal. 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 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

A Note to the ACTIONS excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the 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

(continued)

BASES

ACTIONS (continued)

allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1, A.2, and A.3

With one required 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 required 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.

The required cooling capacity of the alternate method should be ensured by verifying (by administrative means) 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/Main Steam System, the Reactor Water Cleanup System and, feed and bleed to radwaste or condenser.

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.

(continued)

BASES

ACTIONS (continued)

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or 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 functionand 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. An alternate method of reactor coolant circulation that can be used includes (but is not limited to) Reactor Water Cleanup System.

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.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This Surveillance verifies that one required RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The RHR shutdown cooling subsystem or recirculation pump 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the RCIC Steam Supply Line Pressure - Low isolation pressure, 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

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 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 ≤ 212°F. This decay heat is removed in preparation for performing Refueling maintenance operations or for keeping the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling loops of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, 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 RHR Service Water (RHRSW) System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of 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 function that must be accomplished or core damage could result. RHR Shutdown Cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

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, one RHRSW pump providing cooling to the heat exchanger, and the associated piping and valves. In addition, the necessary portions of the Emergency Service Water and River Water Supply Systems and the Ultimate Heat Sink are also required to provide appropriate cooling and a suction source to each required RHRSW pump. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common

(continued)

BASES

LCO (continued)

discharge piping. Thus, to meet the LCO, both pumps and a heat exchanger in one loop or one pump and an associated heat exchanger in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Thus, two RHR pumps in a common RHR subsystem, together with the associated heat exchanger and flow path components, constitute two OPERABLE RHR shutdown cooling subsystems. In addition, the RHR cross tie valve (MO-2010) may be opened to allow pumps in one loop to discharge through the opposite recirculation loop to make a complete subsystem. Additionally, 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 redundancy. Operation of 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 of a recirculation pump or one RHR shutdown cooling subsystem is required.

Note 1 permits both required RHR shutdown cooling subsystems to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one required RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the 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.

(continued)

BASES (continued)

APPLICABILITY

In MODE 4, the RHR Shutdown Cooling System must be OPERABLE and shall be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 212°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 RCIC Steam Supply Line Pressure - Low isolation pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above the RHR shutdown cooling isolation interlock pressure (which is slightly higher than the RCIC Steam Supply Line Pressure - Low isolation 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 RCIC Steam Supply Line Pressure - Low isolation pressure is typically accomplished by condensing the steam in the main condenser. Providing this additional overlap between the different pressures allows a smooth transition between these methods of decay heat removal. 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 RCIC Steam Supply Line Pressure - Low isolation pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR)—Low Water Level."

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

(continued)

BASES

ACTIONS (continued)

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.

A.1

With one of the two required 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 required 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 administrative means) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. For example, if the length of time after shutdown is such that losses to ambient surroundings are sufficiently large so as to prevent RCS temperature from increasing, Required Action A.1 would be fulfilled for one inoperable subsystem. Other alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, feed and bleed to the torus via SRVs, Reactor Water Cleanup System, reactor cavity floodup and Fuel Pool Cleanup System return to the reactor cavity.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation except as 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 alternate method may consist of the losses to ambient surroundings if such losses are sufficiently large so as to prevent RCS temperature from increasing and if natural circulation has been established. 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. Alternate methods of reactor coolant circulation that can be used include (but are not limited to) raising reactor water level above the minimum natural circulation level (i.e.. lowest turnaround point for water in the steam separator) and Reactor Water Cleanup System.

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

SR 3.4.8.1

This Surveillance verifies that one required RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The RHR shutdown cooling subsystem or recirculation pump 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.

(continued)

BASES (continued)

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 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.

Figure 3.4.9-1 contains P/T limit curves for heatup, cooldown, and inservice leakage and hydrostatic testing, and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides limits for both heatup and criticality.

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 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 Appendix H of 10 CFR 50 (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 criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leakage and hydrostatic testing.

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. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Reference 7 approved the curves and limits specified in this section. Since the P/T limits are not derived from any DBA, there are no acceptance

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

LCO

The elements of this LCO are:

a. RCS pressure and temperatures are within the limits of the applicable curves of Figure 3.4.9-1 and heatup or cooldown rates are ≤ 100° F/hr during RCS heatup and cooldown, and ≤ 20° F/hr during pressure testing (e.g. hydrostatic testing). Note: The P/T limits and corresponding heatup/cooldown rates of either Curve A or B may be applied while achieving or recovering from test conditions. Curve A applies during pressure testing and when the limits of Curve B cannot be maintained;

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;

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;

d. RCS pressure and temperature are within the criticality limits specified in Figure 3.4.9-1 prior to achieving criticality; and

e. The temperatures at the reactor vessel head flange and the shell adjacent to the head flange are ≥ 74° 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.

(continued)

BASES

LCO (continued)

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice 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 existences, sizes, and orientations 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.

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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 > 212°F. Several methods may be used, including comparison with pre-analyzed transients, 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 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 3.4.9.1

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 increments, 30 minutes permits a reasonable time for assessment and correction of minor deviations. The limits

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

of Figure 3.4.9-1 are met when operation is to the right of the applicable limit curve.

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be initiated and discontinued when the criteria given in the relevant plant procedure for starting and ending the activity are satisfied. During heatups and cooldowns, the temperatures at the reactor vessel shell adjacent to the shell flange, the reactor vessel bottom drain, recirculation loops A and B, and the reactor vessel bottom head shall be monitored. During inservice hydrostatic or leak testing, the reactor vessel metal temperatures at the outside surface of the bottom head in the vicinity of the control rod drive housing and reactor vessel shell adjacent to the shell flange shall be monitored.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing.

SR 3.4.9.2

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 Figure 3.4.9-1 are met when operation is to the right of the applicable limit curve.

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 3.4.9.3 and SR 3.4.9.4

Differential temperatures within the applicable limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.3 and SR 3.4.9.4 (continued)

ensures that the assumptions of the analysis for the startup of an idle recirculation pump (Ref. 8) 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.

For SR 3.4.9.3, an acceptable means of measuring Reactor Pressure Vessel (RPV) coolant temperature is by using the saturation temperature corresponding to reactor steam dome pressure.

Acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 include but are not limited to comparing the temperatures of the operating recirculation loop and the idle loop. The idle loop and RPV coolant temperature using saturation temperature corresponding to reactor steam dome pressure, or the idle loop and the bottom head coolant temperature with flow through the bottom head drain.

SR 3.4.9.3 and SR 3.4.9.4 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 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

Limits on temperature at the reactor vessel head flange and the shell adjacent to the head flange 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 (continued)

SR 3.4.9.5 requires that temperatures at the reactor vessel head flange and the shell adjacent to the head flange must be verified to be above the limits within 30 minutes before and 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 temperatures at the reactor vessel head flange and the shell adjacent to the head flange are required by SR 3.4.9.6 because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the temperatures at the reactor vessel head flange and the shell adjacent to the head flange are required every 12 hours by SR 3.4.9.7 to ensure the temperatures are within the specified limits.

The 30 minute Frequency for SR 3.4.9.5 and SR 3.4.9.6 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 for SR 3.4.9.7 is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. However, per SR 3.0.4, the Surveillance needs to be met prior to tensioning, i.e., verified within 30 minutes of the start of tensioning. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperatures ≤ 80°F in Mode 4. SR 3.4.9.7 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature ≤ 100°F in Mode 4. 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 limits specified.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix G, December 1995
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. C. Shiraki (NRC) to L. Liu (IELP), TS Amendment No. 172 to Facility Operating License No. DPR-49, dated August 12, 1991.
8. UFSAR, Section 15.4.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 and transients.

APPLICABLE SAFETY ANALYSES

The reactor steam dome pressure of ≤ 1025 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. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% fuel cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)").

Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specified reactor steam dome pressure limit of ≤ 1025 psig ensures the plant is operated within the assumptions of the reactor vessel overpressure protection analysis. Operation above the limit may result in a transient response more severe than analyzed.

APPLICABILITY

In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these

(continued)

BASES

APPLICABILITY (continued)

MODES, the reactor may be generating significant steam and the 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 occurring while pressure is greater than the limit is minimized.

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 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1025 psig ensures that the initial conditions of the reactor 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. UFSAR, Section 5.2.2.

2. APED 23A7210, Supplemental Reload Licensing Report for DAEC.

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 consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) System, and 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 HPCI and CS systems.

On receipt of an initiation signal, after the appropriate time delays for the Diesel Generators (DGs) to start and provide power to the 4160 VAC bus, assuming the concurrent Loss of Offsite Power (LOOP), ECCS pumps automatically start; 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 HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, the ADS timed sequence would be allowed to time out and open the selected Safety Relief Valves (SRVs) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly precluding HPCI from injecting to the vessel, and the LPCI and CS subsystems cool the core.

BASES

BACKGROUND (continued)

Water from the break returns to the suppression pool where it is used again. Water in the suppression pool may be circulated through a heat exchanger cooled by the RHR Service Water System to provide long term cooling, after adequate core cooling has been established and after the applicable timed interlocks have expired, approximately one minute following a LOCA. Depending on the location and size of 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. Although no credit is taken in the safety analysis for the RCIC System, it performs a similar function as HPCI, but has reduced makeup capability. Nevertheless, it will help maintain inventory and cool the core while the RCS is still pressurized following a Reactor Pressure Vessel (RPV) isolation.

The combined operation of 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 equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started approximately 5 seconds after AC power is available. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow on-line testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There is one LPCI System (Ref. 2), consisting of four motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the "selected" recirculation loop. The LPCI System is equipped with a Loop Select Logic that determines which, if any, of the recirculation loops has been broken and "selects" the non-broken loop for injection. (Ref. 15).

BASES

BACKGROUND (continued)

The LPCI System is designed to provide core cooling at low RPV pressure assuming operation of 3 out of 4 RHR pumps. Upon receipt of an initiation signal, all four LPCI pumps are automatically started (A and B pumps approximately 10 seconds after AC power is available, and C and D pumps approximately 15 seconds after AC power is available). 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 "selected" recirculation loop. The LPCI swing bus, a "power-seeking" logic, ensures that the AC distribution bus for the LPCI and Recirculation System valves that must re-align for injection into the RPV are connected to an OPERABLE DG, assuming LOOP (Ref. 15). When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the selected recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for the four LPCI pumps to route water from the suppression pool, to allow on-line testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

The HPCI System (Ref. 3) 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 Feedwater System line, where the coolant is distributed within the RPV through the Feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI 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 if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard Main Steamline Isolation Valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psid to 1135 psid, vessel to pump suction). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed.

(continued)

BASES

BACKGROUND (continued)

As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Although the HPCI System is designed to achieve a design flow rate within 30 seconds from the receipt of an initiation signal (Ref. 3), the accident analysis shows acceptable results assuming HPCI start times (from initiation signal to full flow and injection valve full open) as long as 45 seconds (Ref. 13). Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting 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. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS subsystem discharge lines are kept full of water using a "keep fill" system (jockey pump system). The HPCI System is normally aligned to the CST. The height of water in the CST is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the Feedwater line connection for HPCI is such that the water in the Feedwater lines keeps the remaining portion of the HPCI discharge line full of water. Therefore, HPCI does not require a "keep fill" system when its suction is aligned to the CST. When HPCI suction is aligned to the suppression pool and the system is not in operation, an alternate means of keeping the discharge piping full is required to support system OPERABILITY.

The ADS (Ref. 4) consists of 4 of the 6 SRVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI 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 (CS and LPCI), so that these subsystems can provide coolant inventory makeup. Each of the SRVs used for automatic depressurization is equipped with one nitrogen accumulator and associated inlet check valves. The accumulator provides the pneumatic power to actuate the valves.

(continued)

BASES (continued)

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 Reference 8. The results of these analyses are also 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 a 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 Recirculation System suction pipe break LOCA, failure of Division II of 125 VDC power is considered the most severe failure. For a small break LOCA, HPCI failure is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each ECCS injection/spray subsystem and four ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the LPCI System, and one HPCI System. The low pressure ECCS

(continued)

BASES

LCO (continued)

subsystems are defined as the two CS subsystems and the LPCI System.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

The LPCI System may be considered OPERABLE during alignment and operation for decay heat removal (i.e.- Shutdown Cooling) when below the actual RHR Shutdown Cooling interlock pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. 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. In addition, the risk of a LOCA during the transition from the RHR interlock pressure to cold shutdown is minimal.

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, when reactor steam dome pressure is ≤ 150 psig, HPCI is not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. In MODES 2 and 3, when reactor steam dome pressure is ≤ 100 psig, ADS is not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS – Shutdown."

(continued)

ACTIONS

A.1

If any one RHR pump is inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE pumps provide adequate core cooling during a LOCA. However, overall LPCI reliability is reduced, because a single failure in one of the remaining OPERABLE pumps, concurrent with a LOCA, may result in LPCI not being able to perform its intended safety function. The 30 day Completion Time is based on a reliability study cited in Reference 12 that evaluated the impact on ECCS availability, assuming 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 allowable repair times (i.e., Completion Times).

B.1

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, 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. 12) that evaluated the impact on ECCS availability, assuming 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 out of service times (i.e., Completion Times).

BASES

ACTIONS (continued)

C.1 and C.2

If any one low pressure Core Spray (CS) subsystem is inoperable in addition to one or two RHR pump(s), adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystems. This condition results in a compliment of remaining OPERABLE low pressure ECCS (i.e., one CS and either two or three LPCI pumps) whose makeup capacity is bounded by the minimum makeup capacity evaluated in the accident analysis, which assumes the limiting single component failure of Division II of 125 VDC (Reference 11). However, overall ECCS reliability is reduced because a single active component failure in the remaining low pressure ECCS, concurrent with a design basis LOCA, could result in the minimum required ECCS equipment not being available. Since both a CS subsystem is inoperable and a reduction in the makeup capability of the LPCI System has occurred, a more restrictive Completion Time of 72 hours is required to restore either the CS subsystem or the RHR pump(s) to OPERABLE status. The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

D.1

If both low pressure Core Spray (CS) subsystems are inoperable, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystem (LPCI). However, overall ECCS reliability is reduced because a single active component failure in the LPCI subsystem, concurrent with a design basis LOCA, could result in the minimum required ECCS equipment not being available. Since both CS subsystems are inoperable, a more restrictive Completion Time of 72 hours is required to restore one CS subsystem to OPERABLE status.

BASES

ACTIONS

D.1 (continued)

The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

E.1 and E.2

If the inoperable low pressure ECCS subsystem 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.

F.1 and F.2

If the HPCI System is inoperable and the RCIC System is immediately verified to be OPERABLE, the HPCI 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 subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Immediate verification of RCIC OPERABILITY is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be immediately verified, however, Condition J must be immediately 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.

BASES

ACTIONS

F.1 and F.2 (continued)

A 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

G.1 and G.2

If any one RHR pump is inoperable in addition to an inoperable HPCI System, the inoperable RHR pump or the HPCI System must be restored to OPERABLE status within 7 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a DBA-LOCA could result in the minimum complement of ECCS not being available to perform the intended safety function. Since a high pressure system (HPCI) is inoperable and a loss of redundancy in the LPCI System has occurred, a more restrictive Completion Time of 7 days is required to restore either the HPCI System or RHR pump to OPERABLE status. The Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair time in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

H.1 and H.2

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, in addition to an inoperable HPCI System, the inoperable low pressure ECCS subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this Condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly 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. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours

BASES

ACTIONS

H.1 and H.2 (continued)

is required to restore either the HPCI System or the low pressure ECCS subsystem to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. This Completion Time has been found to be acceptable through operating experience.

I.1 and I.2

If any one ADS valve is inoperable in addition to the HPCI System being inoperable, adequate core cooling (for small break LOCAs) is ensured by the remaining ADS valves in combination with either the CS or LPCI subsystems. However, overall ECCS reliability is significantly reduced because a single active component failure (i.e., failure of one of the three remaining OPERABLE ADS valves) concurrent with a small break LOCA could result in the minimum required ECCS equipment not being available. Since both an ADS valve and the HPCI System are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the ADS valve or the HPCI System to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

J.1 and J.2

If any Required Action and associated Completion Time of Condition F, G, H or I is not met, 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.

BASES

ACTIONS (continued)

K.1

The LCO requires four ADS valves to be OPERABLE in order to provide the ADS function. Reference 13 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only three 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. This 30 day Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probalistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

L.1 and L.2

If any one low pressure ECCS subsystem is inoperable for reasons other than Condition A, in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystem. However, overall ECCS reliability is reduced because a single active component failure concurrent with a LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure system (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS subsystem or the ADS valve to OPERABLE status. This Completion Time was developed using engineering judgement based on a reliability study cited in Reference 12 and methodology for calculating safe test intervals and allowable repair times in Reference 14. In addition, risk insights from the DAEC Probabilistic Safety Assessment (PSA) were used to validate that the Completion Time is appropriate. This Completion Time has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

M.1 and M.2

If any Required Action and associated Completion Time of Condition K or L is not met, or if two or more 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 ≤ 100 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.

N.1

When multiple ECCS subsystems are inoperable, as stated in Condition N, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

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 HPCI System and CS and LPCI subsystems full of water (up to the normally closed injection valve) ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a potential water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points. Other acceptable methods include verifying the absence of the Core Spray or RHR Discharge Line Low Pressure annunciator, or verifying that HPCI suction is aligned to the CST with CST level greater than 8 feet. The 31 day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2

Verifying the correct alignment for power operated and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an 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 manual valves or valves that cannot be inadvertently misaligned, such as check valves. For the HPCI 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 once 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 only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

In Mode 3 with reactor steam dome pressure less than the actual RHR interlock 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 Note 1, which allows the LPCI System 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 interlock pressure, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

Verification every 31 days that a 100 day supply of nitrogen exists for each ADS accumulator ensures adequate nitrogen pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that following a failure of the pneumatic supply to the accumulator, each ADS valve can be actuated at least 5 times up to 100 days following a LOCA (Reference 4). This SR can be met by either: 1) verifying that the drywell nitrogen header supply pressure is ≥ 90 psig, or 2) when drywell nitrogen header supply pressure is < 90 psig, using the actual accumulator check valve leakage rates obtained from the most-recent tests to determine, analytically, that a 100 day supply of nitrogen exists for each accumulator. The results of this analysis can also be used to determine when the 100 day supply of nitrogen will no longer exist for individual ADS accumulators, and when each ADS valve would subsequently be required to be declared inoperable, assuming the drywell nitrogen supply pressure is not restored to ≥ 90 psig. The 31 day Frequency takes into consideration administrative controls over operation of the nitrogen system and alarms for low nitrogen pressure.

SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.6

The performance requirements of the low pressure 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 low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure 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 a LOCA. These values may be established during preoperational testing or by analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.6 (continued)

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow is tested at both the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Reactor steam pressure must be ≥ 940 psig to perform SR 3.5.1.5, the high pressure test, and ≤ 160 psig to perform SR 3.5.1.6, the low pressure test. Adequate steam flow is represented by approximately 0.5 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test 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 HPCI is inoperable.

Therefore, SR 3.5.1.5 and SR 3.5.1.6 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 hour allowance to reach the required pressure and flow is sufficient to achieve stable conditions for testing and provide a reasonable time to complete the SRs.

The Frequency for SR 3.5.1.4 and SR 3.5.1.5 is in accordance with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.1.6 is based on the need to perform the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.7

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 HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. As part of this SR for the LPCI system, a verification of the "power-seeking" logic for the LPCI "Swing Bus" (1B34A and 1B44A), i.e., the ability to transfer power sources from either AC Essential Bus upon loss of power (either AC or 125 VDC), is included. This verification, when coupled with the verification of the "break-before-make" coordination of the breakers in SR 3.8.7.2, demonstrate the ability of the Swing Bus to perform its intended safety function in support of the Loop Select design of the LPCI system without compromising the independence of the AC Distribution System (Reference 16). This SR also ensures that the HPCI System will automatically restart on an RPV low water level signal received subsequent to an RPV high water level trip and that the suction is automatically transferred from the CST to the suppression pool on a CST Low Water Level Signal or Torus High Water Level Signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

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 two Notes. The first Note 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. The second Note is added to SR 3.5.1.7 to allow the surveillance to be met by performing the test in any number of sequential and/or overlapping steps, rather than in a single, contiguous performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

This is necessary because testing the entire LPCI Loop Select Logic would interfere with forced reactor coolant circulation and/or decay heat removal functions and require multiple LPCI System starts to demonstrate all the Loop Select Logic features (e.g., injections paths, single loop operation and "swing" bus). Therefore, each of the required features can be tested either individually or in appropriate combinations (including overlap with other LCO 3.5.1 surveillances, the Instrumentation surveillances required by LCO 3.3.5.1 and the "swing" bus breaker coordination surveillance in LCO 3.8.7), such that the overall function is tested on the required Frequency.

SR 3.5.1.8

The ADS designated SRVs 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. SR 3.5.1.9 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 24 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the 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, since the valves are individually tested in accordance with SR 3.5.1.9. This prevents an RPV pressure blowdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.9

A manual actuation of each ADS valve is performed to verify that the valve and solenoid are functioning properly and that no blockage exists in the SRV discharge lines. This is demonstrated by the response of the turbine control or bypass valve or by a change in the measured flow or by any other method suitable to verify steam flow (such as actuation of the SRV tailpipe pressure switches or thermocouples). 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 SR. Adequate pressure at which this SR is to be performed is approximately 150 psig which is the lowest pressure EHC can maintain. Adequate steam flow is represented by approximately 1.15 turbine bypass valves open. Reactor startup is allowed prior to performing this SR 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 is reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance. SR 3.5.1.8 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 is based on the need to perform the 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.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.3.2.2.3.
2. UFSAR, Section 6.3.2.2.4.
3. UFSAR, Section 6.3.2.2.1.
4. UFSAR, Section 6.3.2.2.2.
5. UFSAR, Section 15.4.7.
6. UFSAR, Section 15.6.5.
7. UFSAR, Section 15.6.6.
8. 10 CFR 50, Appendix K.
9. UFSAR, Section 6.3.3.
10. 10 CFR 50.46.
11. UFSAR, Section 6.3.1.1.2.
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
13. NEDC-32915P, "Duane Arnold Energy Center GE12 Fuel Upgrade Project", November 1999.
14. NEDO-10739, Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, January 1973.
15. UFSAR, Section 7.3.1.1.2.4.
16. J. Hall (NRC) to L. Liu (IELP), "LPCI Swing Bus Design Modification (TAL No. 69556), "dated January 19, 1989.

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 Core Spray (CS) System is provided in the Bases for LCO 3.5.1, "ECCS-Operating".

The Low Pressure Coolant Injection (LPCI) Mode of the Residual Heat Removal (RHR) System, for the application of this specification, takes on a different definition than is described in the Bases for LCO 3.5.1 "ECCS-Operating". In the application of "ECCS-Shutdown", the low pressure ECCS subsystems consist of two CS subsystems and two LPCI subsystems. Each LPCI subsystem consists of one motor driven RHR pump, piping, and valves to transfer water from the suppression pool to the Reactor Pressure Vessel (RPV). Only a single RHR pump is required per subsystem because of the larger injection capacity in relation to a CS subsystem.

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 low pressure ECCS pump is required, post LOCA, to maintain adequate reactor vessel water level. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one low pressure ECCS subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two low pressure ECCS subsystems are required to be OPERABLE in MODES 4 and 5.

The low pressure ECCS subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two low pressure ECCS subsystems are required to be OPERABLE. For this specification, the low pressure ECCS subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or Condensate Storage Tank (CST) to the

(continued)

BASES

LCO (continued)

Reactor Pressure Vessel (RPV). Each LPCI subsystem consists of one motor driven RHR pump, piping, and valves to transfer water from the suppression pool to the RPV. Only a single RHR pump is required per subsystem because of the larger injection capacity in relation to a CS subsystem. In MODES 4 and 5, the RHR System cross tie valve is not required to be open. The necessary portions of Emergency Service Water are also required to provide appropriate cooling to each required CS subsystem. One LPCI subsystem may be aligned for decay heat removal and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. 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 low pressure ECCS 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 ≥ 21 ft 1 inch above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncover 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 ≤ 100 psig, and the CS and LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS subsystems can provide sufficient flow to the vessel and because insufficient reactor pressure is available to drive the HPCI turbine.

(continued)

BASES (continued)

ACTIONS

A.1 and B.1

If any one required low pressure ECCS subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status in 4 hours. In this condition, the remaining OPERABLE subsystem can provide sufficient vessel 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 low pressure ECCS subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, 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 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

With both of the required ECCS subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs 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 subsystem must also be restored to OPERABLE status within 4 hours.

If at least one low pressure ECCS 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 isolation capability for each associated secondary containment penetration flow path not isolated that is

(continued)

BASES

ACTIONS

C.1, C.2, D.1, D.2, and D.3 (continued)

assumed to be isolated to mitigate radioactivity releases is available (i.e., at least one secondary containment isolation valve or damper 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 communications 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.). OPERABILITY may be verified by an administrative check, or 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, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

The 4 hour Completion Time to restore at least one low pressure ECCS 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of 7.0 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 LPCI System pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the LPCI subsystem(s) is (are) inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2 (continued)

When suppression pool level is < 8.0 ft, the CS System is considered OPERABLE only if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CS pump. Therefore, a verification that either the suppression pool water level is ≥ 8.0 ft or that CS is aligned to take suction from the CSTs and the CSTs contain ≥ 75,000 gallons of water, equivalent to 11 ft in one CST or ≥ 7 ft in both CSTs, ensures that the CS System can supply at least 75,000 gallons of makeup water to the RPV. However, as noted, only one required CS subsystem may take credit for the CST option during OPDRVs. During OPDRVs, the volume in the CST may not provide adequate makeup if the RPV were completely drained. Therefore, only one CS subsystem is allowed to use the CST. This ensures the other required ECCS subsystem has adequate makeup volume.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool water level and CST water level variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to an abnormal suppression pool or CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.7 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

SR 3.5.2.4

Verifying the correct alignment for 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 (continued)

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 manual valves or 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 realigned from or to the RHR shutdown cooling mode. 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 coverage prior to postulated fuel uncovery. This will ensure adequate core cooling if an inadvertent RPV draindown should occur.

REFERENCES

1. UFSAR, Section 5.4.7.2.6.

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 the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) 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 Feedwater System line, where the coolant is distributed within the RPV through the Feedwater sparger. Suction piping is provided from the Condensate Storage Tank (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 a main steam line upstream of the associated inboard Main Steamline Isolation Valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures 150 psig to 1120 psig. 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 from and 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 piping is kept full of water. The RCIC System is normally aligned to the CST. The height of water in the CST is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep fill" system when its suction is aligned to the CST. When RCIC suction is aligned to the suppression pool and the system is not in operation, an alternate means of keeping the discharge piping full is required to support system OPERABILITY.

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, however, the system satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

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 for maintaining RPV inventory during an isolation event.

APPLICABILITY

The RCIC System is required to be OPERABLE during 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

(continued)

BASES

APPLICABILITY (continued)

required to be OPERABLE since the low pressure ECCS subsystems can provide sufficient flow to the RPV and since RPV pressure is insufficient to drive the RCIC turbine.

ACTIONS

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a Loss of Coolant Accident (LOCA). OPERABILITY of HPCI is therefore verified immediately within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified immediately, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the 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. 3) that evaluated the impact on ECCS availability, assuming 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 out of service times. Because of similar functions of HPCI and RCIC, the out of service times (i.e., Completion Times) determined for HPCI are also applied to RCIC.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI 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.

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 potential water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. Another acceptable method is verifying that RCIC suction is aligned to the CST with the CST level greater than 8 feet. 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 power operated and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.2 (continued)

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 manual valves or 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 once 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.

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 is tested both at the higher and lower operating ranges of the system. 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. Reactor steam pressure must be ≥ 940 psig to perform SR 3.5.3.3, the high pressure test, and ≤ 160 psig to perform SR 3.5.3.4, the low pressure test. Adequate steam

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.3 and SR 3.5.3.4 (continued)

flow is represented by approximately 0.4 turbine bypass valves open. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed 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 Surveillance 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 hour allowance to reach the required pressure and flow is sufficient to achieve stable conditions for testing and provide a reasonable time to complete the SRs.

The Inservice Testing Program Frequency for SR 3.5.3.3 is every 92 days. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform the Surveillance under 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 3.5.3.5

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on an RPV low water level signal received subsequent to an RPV high water level trip and that the suction is automatically transferred from

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

the CST to the suppression pool on a CST Low 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.

The 24 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the 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. UFSAR, Section 3.1.2.4.4.
2. UFSAR, Section 5.4.6.
3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs 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 Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material. The Primary Containment in the General Electric Mark-I containment design consists of a drywell section and a suppression chamber interconnected by a vent pipe system. The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion, the so-called "inverted light bulb" shape, built to the requirements of Section III to the ASME code. The drywell is equipped with hatches and a personnel airlock for equipment and personnel access. The drywell is enclosed in a reinforced-concrete structure for shielding purposes. The pressure suppression chamber is also a Section III steel pressure vessel built in the shape of a torus, which is located below and encircles the drywell. The pressure suppression chamber contains the pressure suppression pool, which serves as the heat sink during Loss-of-Coolant Accidents and other transients in which the primary heat sink (Main Condenser) is lost. The suppression chamber is connected to the drywell via a series of large vent pipes that direct the energy released from the primary reactor system into the suppression pool. The energy can also be directly transferred from the primary reactor system to the suppression pool via the safety/relief valves, High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) turbine exhaust lines.

The isolation devices for the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Lock"; and

c. All equipment hatches and manways are closed.

This Specification ensures that the performance of the primary containment, in the event of a 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, 4 and 5), 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 2.0% by weight of the containment air

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 43 psig (Ref. 1).

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

LCO

Primary containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the pressure suppression function is accomplished and the suppression chamber 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 leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock 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 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 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.

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

If primary 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits (SR 3.6.1.2.1), resilient seal primary containment purge valve leakage limits (SR 3.6.1.3.4), or main steam isolation valve leakage limits (SR 3.6.1.3.9) 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 the Primary Containment Leakage Rate Testing Program. As left leakage prior to the first startup after performing a required 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 Primary Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

Maintaining the pressure suppression function of 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. This SR

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 (continued)

maintains drywell to suppression chamber differential pressure during a 10 minute period to measure and ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and verifying that the increase in suppression chamber pressure is less than 0.009 psi per minute when averaged over a 10 minute period. The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is required that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs.

REFERENCES

1. UFSAR, Section 6.2.
2. UFSAR, Section 15.9.
3. 10 CFR 50, Appendix J, Option B.
4. NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance - Based Option of 10 CFR Part 50, Appendix J."
5. ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirement."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

One double door primary containment air lock has been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. The air lock is 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 a pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors contains a single gasketed seal to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in primary containment internal pressure results in increased sealing force on each door).

Each air lock is nominally a right circular cylinder, 12 ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. 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 interlock mechanism has failed, by manually performing the interlock function.

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary

(continued)

BASES

BACKGROUND (continued)

containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety 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 2.0% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 43 psig (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

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.

The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

As part of the primary containment pressure boundary, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be

(continued)

BASES

LCO (continued)

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 or exit from primary containment.

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 to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the outer 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 OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial measures 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 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.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3

With one primary containment air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1) in the 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 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 that the OPERABLE door is being maintained closed.

Required Action A.3 ensures that the 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 in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas 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 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

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

entry and exit for 7 days under administrative controls. Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on TS-required equipment or activities on equipment 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 administrative controls consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during entry and exit, and assuring 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, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the 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).

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 that allows these doors

(continued)

BASES

ACTIONS

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

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

If the air lock is 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 the overall air lock leakage is not within limits. In many instances, 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 the overall air lock leakage not within limits, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This 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, Required Action C.3 requires the air lock to be restored to OPERABLE status within 24 hours. 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 the air lock.

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

(continued)

BASES

ACTIONS

D.1 and D.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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. 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 Primary Containment Leakage Rate Testing Program.

Testing of the air lock requires the installation of a strongback on the inner door to keep it closed during testing, since the air lock is tested by pressurizing the space between the inner and outer doors. Without the strongback, the inner door could be forced open by the pressure against it in the non-accident direction. Opening the air lock door to remove the strongback (or other test equipment), does not require further leak testing, as long as the inner door seal is not disturbed.

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 requires the results of airlock leakage tests be evaluated against the acceptance criteria of the Primary Containment Leakage Rate Testing Program, 5.5.12. This ensures that the airlock leakage is properly accounted for in determining the combined Type B and C primary containment leakage.

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

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 containment pressure, 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 airlock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during use of the airlock.

REFERENCES

1. UFSAR, Section 6.2.1.1.
2. 10 CFR 50, Appendix J, Option B.
3. UFSAR, Section 6.2.1.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

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) to within limits. 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 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 primary containment functions assumed in the safety analyses will be maintained. These isolation devices are either passive or active (automatic). Closed manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves and other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

The reactor building-to-suppression chamber vacuum breakers serve a dual function, one of which is primary containment isolation. However, since the primary safety function of the vacuum breakers would not be available if the normal PCIV actions were taken, the PCIV OPERABILITY requirements are not applicable to the reactor building-to-suppression chamber vacuum breakers valves. Similar surveillance requirements in the LCO for reactor building-to-suppression chamber vacuum breakers provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

(continued)

BASES

BACKGROUND (continued)

Other valves, such as torus suction valves and pump minimum flow valves, also serve a dual function. These dual function valves, have both a primary and secondary safety function, the primary function being core cooling and the secondary function being containment isolation. As such, these dual function valves are not subject to the ACTIONS of this LCO (References 6 and 7) and are not included in the valve list in the plant Administrative Control Procedures.

The primary containment purge lines are 18 inches in diameter and the vent lines are also 18 inches in diameter. The 18 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. However, these purge valves may be open when being used for pressure control, inerting, de-inerting, ALARA or air quality considerations. These valves are qualified to be open because an atmospheric relief valve damper (set to actuate at 10 inches water gauge pressure) is installed downstream of the containment vent/purge valves to protect the SBGT System ductwork from overpressure conditions that could be present during certain venting conditions. The inboard isolation valves on the 18 inch vent lines have 2 inch bypass lines around them for use during normal reactor operation.

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 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 DBA that results in a release of radioactive material within primary containment is a LOCA. In the analysis for this accident, it is assumed that PCIVs are either closed or close within the required isolation times 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 Reference 1, the MSLB is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds, which is conservative with respect to the 10.5 second closure time assumed in the analysis. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that within approximately 60 seconds of the accident, isolation of the primary containment is complete and leakage is terminated, except for the maximum allowable leakage rate, L_a. The primary containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times. Isolation valves on process lines that communicate directly with the reactor vessel are required to reach the fully closed position in various times less than 60 seconds in order to limit vessel inventory loss to prevent level from dropping below the top of active fuel (Reference 4).

PCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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 18 inch purge valves must be blocked to prevent full opening. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers." The valves covered by this LCO are listed in the plant Administrative Control Procedures and PCIV stroke times are provided in the Inservice Testing Program.

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

(continued)

BASES

LCO (continued)

Reference 2 or in applicable administrative procedures. Purge valves with resilient seals, 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.

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 in MODES 4 and 5. Shutdown Cooling System Isolation valves, however, are required to be OPERABLE in Modes 4 and 5 to prevent inadvertent reactor vessel draindown. These valves are only required to be OPERABLE for those functions required OPERABLE by the associated instrumentation per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." Per Table 3.3.6.1, if RHR Shutdown Cooling System integrity is maintained (i.e., no OPDRVs in progress within the RHR Shutdown Cooling System boundary) only one trip system and its associated PCIVs are required to be OPERABLE in Modes 4 and 5. Specifically, either an inboard trip system and its associated PCIVs (MO-1908 and MO-2003) or the outboard trip system and its associated PCIVs (MO-1909 and MO-1905) must be OPERABLE. (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. For valves requiring local operation, 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. For valves that can be operated remotely from the control room, the valve hand

(continued)

BASES

| ACTIONS (continued)

switch is tagged or controlled per plant procedures, identifying that the valve is open under administrative control and must be closed should an isolation signal occur. In the event of an isolation signal, plant procedures direct control room operators to verify all automatic actions occur, and to manually initiate those automatic actions that should have occurred but did not. This will ensure the control room operators verify any valves open under administrative control close in response to an isolation signal. If any of the open valves are unable or fail to close automatically, the control room operators will manually close them.

Note 1 allows penetrations to be opened for other operational reasons, such as draining, venting, etc.

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 that appropriate remedial actions are taken, if necessary, if the affected system(s)/function(s) are rendered inoperable by an inoperable PCIV. Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded due to excessive leakage on any PCIV such that overall containment leakage criteria could be 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 MSIV or purge valve leakage not within limits, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve, flange, etc., to the primary containment. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. The 18 inch primary containment purge valves are equipped with resilient seals that require compressed air to ensure leak tightness. Therefore, both inboard and outboard 18 inch containment purge valves for the affected penetration are required to have functional resilient seals in order to provide an isolation barrier that cannot be affected by a single active failure. Thus, an acceptable isolation barrier is established when both inboard and outboard purge valves are de-activated in the closed position, with the resilient seals pressurized to ensure leak tightness of both purge valves. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

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

Required Action A.2 is modified by a Note that 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. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except for MSIV or purge valve leakage not within limits, 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. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

(continued)

BASES

ACTIONS

B.1 (continued)

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

C.1 and C.2

Condition C is applicable to Type C islation valves (UFSAR Section 6.2.4.2) in the reactor building closed cooling water (MO-4841A and MO-4841B) and drywell cooling (CV-5718A, CV-5718B, CV-5704A and CV-5704B) systems and is also applicable to excess flow check valves. With one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated.

The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. A check valve may not be used to isolate the affected penetration.

Required Action C.1 must be completed within 72 hours for lines other than Excess Flow Check Valve (EFCV) lines and 12 hours for EFCV lines. The Completion Time of 72 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Reference 9.

The Completion Time of 12 hours for EFCVs is reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. For affected penetrations that have been isolated in accordance with Required Action C.1, the affected penetration flow path(s) must be verified to be

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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 valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

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

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means.

Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1

With one or more penetration flow paths with one or more MSIVs not within leakage limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. When a penetration is isolated, the leakage rate for the isolated

(continued)

BASES

ACTIONS

D.1 (continued)

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 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.

E.1

In the event one or more containment purge valves are not within the purge valve leakage limits, purge 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 will maintain leak tightness under LOOP-LOCA conditions. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. In addition, for the valve or flange to be acceptable for use as the OPERABLE isolation device, it must meet all the design requirements for the PCIV it is replacing, such as, 10 CFR 50, Appendix J leakage testing, seismic qualifications, piping code class provisions, etc. The specified Completion Time is reasonable, to take the ACTIONS or return the purge valve leakage to within limits, given the low probability of an event during this short period of time.

E.2

If a purge valve with resilient seal is utilized to satisfy Required Action E.1, unlimited operation is not permitted as this method of isolating the penetration is susceptible to single failures that could compromise the leak tightness of the entire penetration (e.g., loss of air compressor, DG failure, etc). Thus, per the Note to Required Action E.2, if this method of isolation is used, the containment purge valve leakage must be restored to within limits within 72 hours. The specified Completion Time is reasonable, considering that one containment purge valve remains sealed so that primary containment integrity is maintained, although not single failure tolerant and the low probability of an event occurring during this time period.

(continued)

BASES

ACTIONS

E.2 (continued)

Required Action E.2 is modified by a Note indicating this Required Action is only required to be performed if a purge valve with resilient seal is used to satisfy Required Action E.1. If th method of isolation is by the use of at least one isolation barrier that cannot be adversely affected by a single active failure, then Required Action E.2 is not required because the integrity of the affected penetration flow path is being maintained by a passive device and unlimited operation is permitted.

E.3

In accordance with Required Action E.3, 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. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Required Action E.3 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 means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

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

(continued)

BASES

ACTIONS (continued)

F.1 and F.2 (continued)

Completion Times are reasonable, based on operating experience, to reach the required 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 PCIVs required to be OPERABLE in MODES 4 or 5, the unit must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) within the RHR Shutdown Cooling System boundary to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended and valve(s) are restored to OPERABLE status. If suspending an OPDRV would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable.

If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. 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 Surevillances that require the valves to be open. The 18 inch purge valves are capable of closing in the enviornment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

(continued)

BASES

SUREVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

The 31 day Frequency was chosen to provide added assurance that the purge valves are The in the correct position.

SR 3.6.1.3.2

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 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 3.6.1.3.3

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 3.6.1.3.5. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.4

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. 3), is required to ensure OPERABILITY. 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 this penetration leak tight (due to the direct path between primary containment and the environment), a Frequency of 184 days was established. The purge system isolation valves are tested in three groups, by penetration: drywell purge exhaust group (CV-4302 and CV-4303), torus purge exhaust group (CV-4300 and CV-4301), and drywell/torus purge supply group (CV-4307, CV-4308 and CV-4306). If the results of a combined leak rate or pressure drop test indicate excessive leakage, credit can be taken for one of the purge valves to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.4 (continued)

satisfy Required Action E.1, if it can be reasonably determined that the purge valve to be credited for isolation is not leaking excessively.

Additionally, this SR must be performed once 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 3.6.1.3.5

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 100 limits and that the core remains covered. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.6

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. A Note has been added for the MSIVs, that allows this SR to be met by any series of sequential, overlapping, or total steps so that proper operation of the MSIVs on receipt of an actual or simulated isolation signal is verified. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this Surveillance when performed at

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.6 (continued)

the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.7

This SR requires a demonstration that a representative sample of reactor instrumentation line Excess Flow Check Valves (EFCVs) are OPERABLE by verifying that the valves cause a marked decrease in flow rate on a simulated instrument line break. This SR provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during the postulated instrument line break event evaluated in Reference 5. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested at least once every 10 years (nominal). The nominal 10 year interval is based on other performance-based testing programs, such as Inservice Testing (snubbers) and Option B to 10 CFR 50, Appendix J. EFCV test failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint (Reference 10).

SR 3.6.1.3.8

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. Other administrative controls, such as those that limit the shelf life of the explosive charges, must also be followed. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.9

The analysis in Reference 8 is based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 100 scfh when tested at ≥ 24 psig. The combined maximum pathway leakage rate for all four main steam lines must be ≤ 200 scfh when tested at ≥ 24 psig. If the leakage rate through an individual MSIV exceeds 100 scfh, the leakage rate shall be restored to ≤ 11.5 scfh. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The frequnecy is required by the Primary Containment Leakage Rate Testing Program.

REFERENCES

1. UFSAR, Chapter 15.6.
2. UFSAR, Table 7.3-1.
3. 10 CFR 50, Appendix J, Option B.
4. UFSAR, Section 7.3.1.1.1.7.
5. UFSAR, Section 1.8.11.
6. J. Franz (IELP) to T. Murley (NRC), "Revised Response to NRC Position on Operability of Safety-Related Dual Function Valves," NG-93-5124, December 7, 1993.
7. G. Kelly (NRC) to L. Liu (IES). " NRC Position on Operability of Safety-Related Dual Function Valves at the Duane Arnold Energy Center (TAC No. 88398), " January 3, 1995.
8. UFSAR Section 6.7.4.3
9. UFSAR Section 3.1.2.5
10. GE BWROG B21-00658-01, "Excess Flow Check Valve Testing Relaxation," dated November 1998.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Air Temperature

BASES

BACKGROUND

The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for a spectrum of break sizes for postulated Loss of Coolant Accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 1). Analyses assume an initial average drywell air temperature of 135°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 340°F (Ref. 2). Both the maximum allowable temperature (340°F) and the peak (DBA) drywell temperature (286.8°F) exceed the drywell design temperature (281°F). This is acceptable since a generic analysis conducted for a similar drywell demonstrates that the higher temperatures can be tolerated with no significant compromise to the original design margins. Exceeding the maximum allowable temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident.

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

(continued)

BASES (continued)

LCO

In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the drywell design temperature. 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

A.1

With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The 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.

B.1 and B.2

If the drywell average air temperature cannot be restored to within 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

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. Drywell air temperature is monitored in all quadrants and at various elevations (referenced to mean sea level). Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

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

REFERENCES

1. UFSAR, Section 6.2.
2. UFSAR, Section 6.2.1.3.3.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Low-Low Set (LLS) Valves

BASES

BACKGROUND

The Safety Relief Valves (SRVs) can actuate in either the safety mode, relief mode (manual), the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the pilot valve. As in the safety mode, opening the pilot valve allows a differential pressure to develop across the main valve piston and opens the main valve. The main valve can stay open with valve inlet steam pressure as low as 50 psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the pilot valves. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.

Two of the SRVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure after reactor pressure has exceeded the scram setpoint and any SRV has opened at its normal steam pilot setpoint, and stay open longer, so that reopening more than one SRV is prevented on subsequent actuations. This mitigates the induced loads on the containment and the thrust loads on the SRV discharge lines by increasing the time between subsequent SRV actuations. Therefore, the LLS function prevents excessive short duration SRV cycles that would occur with valve actuation at the relief setpoint.

Each SRV discharges steam through a discharge line and T-quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower containment load.

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of one SRV operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of SRVs (following the initial opening), and the corresponding

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

higher loads, are avoided. However, this design feature is not critical since simultaneous valve opening is not a concern for Mark I containment, and since simultaneous opening will not cause water swell problems for a BWR (Ref. 3). The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the SRV discharge line resulting from "subsequent actuations" of the SRV during major pressure transients such as MSIV closure or turbine trip without bypass. Furthermore, the LLS function justifies the primary containment analysis assumption that simultaneous SRV openings occur only on the initial actuation for Limiting Transients.

LLS valves satisfy Criterion 3 10 CFR 50.36(c)(2)(ii).

LCO

Two LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analyses (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the SRVs.

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of SRVs. 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 LLS valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one LLS valve inoperable, the remaining OPERABLE LLS valve is adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS valve and the low probability of an event in which the remaining LLS valve capability would be inadequate.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If both LLS valves are inoperable or if the inoperable LLS valve 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Adequate pressure at which this test is to be performed is approximately 150 psig which is the lowest pressure EHC can maintain. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Adequate steam flow is represented by approximately 1.15 turbine bypass valves open. The 24 month Frequency was based on the SRV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 2). 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.

Since steam pressure is required to perform the Surveillance, however, and steam may not be available during a unit outage, the Surveillance may be performed during the startup following a unit outage. Unit startup is allowed

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1 (continued)

prior to performing the test because valve OPERABILITY and the setpoints for overpressure protection are verified in accordance with Reference 2 prior to valve installation. After adequate reactor steam dome pressure and flow are reached, 12 hours is allowed to prepare for and perform the test.

SR 3.6.1.5.2

The LLS designated SRVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.3, "Low-Low Set (LLS) 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 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.

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

REFERENCES

1. UFSAR, Section 5.4.13.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. NEDE-30021-P, Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for DAEC, January 1983.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the two reactor building-to-suppression chamber vacuum breaker assemblies is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breaker assemblies and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief system consists of two vacuum breaker assemblies each consisting of a vacuum breaker and an air operated butterfly valve, located in series in each of two branch lines from a single penetration through the reactor building to a common line that penetrates the suppression chamber airspace. The butterfly valve is actuated by differential pressure and can be remotely operated. The vacuum breaker is self actuating and can be locally operated for testing purposes. Both the butterfly valve and the vacuum breaker valve of each vacuum breaker assembly must be closed to maintain a leak tight primary containment boundary.

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 primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breaker assemblies prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breaker assemblies.

The external vacuum breaker assemblies are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and

(continued)

BASES

BACKGROUND (continued)

limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the reactor building-to-suppression chamber vacuum breaker assemblies are presented in Reference 1 as part of the accident response of the containment systems. Internal vacuum breakers (suppression-chamber-to-drywell) and external vacuum breaker assemblies (reactor building-to-suppression chamber) are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breaker assembly valves to be closed initially and to be fully open at 0.5 psid (Ref. 1). Additionally, of the two reactor building-to-suppression chamber vacuum breaker assembly valves, one is assumed to fail in a closed position to satisfy the single active failure criterion. Design Basis Accident (DBA) analyses require the vacuum breaker assembly valves to be closed initially and to remain closed and leak tight with positive primary containment pressure.

The adequacy of the external vacuum breaker assemblies was determined by considering an inadvertent containment spray operation while the drywell is at the 150°F maximum operating temperature and at a pressure slightly greater than 2 psig.

The results of this evaluation shows that the external vacuum breaker assemblies, with an opening setpoint of 0.5 psid, are capable of maintaining the differential pressure within design limits.

The reactor building-to-suppression chamber vacuum breaker assemblies satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Both reactor building-to-suppression chamber vacuum breaker assemblies are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that both vacuum breaker assembly valves (vacuum breaker and air operated butterfly valve) in each of the two branch lines from the reactor building to the common line that penetrates the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, the requirement ensures both vacuum breaker assembly valves in each branch line will open to relieve a negative pressure in the suppression chamber.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 1, 2, and 3, Suppression Pool Spray System operation may be desirable to mitigate the effects of a DBA. Excessive negative pressure inside primary containment could occur due to inadvertent initiation of this system. Therefore, the vacuum breaker assemblies are required to be OPERABLE in MODES 1, 2, and 3, when Suppression Pool Spray System operation may be desirable, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.

Also, in MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. This event results in a rapid depressurization of the drywell, which 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.

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 reactor building-to-suppression chamber vacuum breaker assemblies OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration branch line flow path.

A.1

With one or two vacuum breaker assemblies with one valve not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable vacuum breaker assembly valve(s) must be restored to OPERABLE status or the open vacuum breaker assembly valves closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression chamber-to-drywell vacuum breakers in LCO 3.6.1.7, "Suppression Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining vacuum breaker assembly valves, the fact that the OPERABLE vacuum breaker assembly valve in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breaker assembly valves to be OPERABLE during this period.

B.1

With one or two vacuum breaker assemblies with two vacuum breaker assembly valves not closed, primary containment integrity is not maintained. Therefore, one open vacuum breaker assembly valve per line must be closed within 1 hour. This 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.

C.1

With one vacuum breaker assembly with one or more vacuum breaker assembly valves inoperable for opening, but known to be closed, the leak tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened, however, if both vacuum breaker assembly valves in at least one vacuum breaker assembly are not OPERABLE.

(continued)

BASES

ACTIONS

C.1 (continued)

Therefore, the inoperable vacuum breaker valve assembly must be restored to OPERABLE status within 72 hours. This is consistent with within 72 hours. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

D.1

With two vacuum breaker assemblies with one or more vacuum breaker assembly valves inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breaker assemblies is lost. Therefore, all vacuum breaker assembly valves in one vacuum breaker assembly must be restored to OPERABLE status within 1 hour. This 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.

E.1 and E.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

Each vacuum breaker assembly valve is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker assembly valve position or by verifying a differential pressure of 0.5 psid is maintained between the reactor building and suppression chamber. If the position indicator of any vacuum breaker assembly valve is inoperable, plant procedures require the position

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

indicator to be restored or the affected vacuum breaker assembly valve be periodically verified to be closed by visual inspection. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker assembly valve status available to operations personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. The first Note allows reactor building-to-suppression chamber vacuum breaker assembly valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breaker assembly valves are controlled by plant procedures and do not represent inoperable vacuum breaker assembly valves. The second Note is included to clarify that vacuum breaker assembly valves open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.6.2

Each vacuum breaker assembly valve must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The 92 day Frequency of this SR was developed based upon Inservice Testing Program requirements to perform valve testing at least once every 92 days.

SR 3.6.1.6.3

Demonstration of vacuum breaker assembly valve opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker assembly valve full open differential pressure of ≤ 0.614 psid is valid. The 12 month Frequency is based upon the assumption of a 12 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 6.2.

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 7 internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow noncondensible gasses 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 reflood water flowing out of a postulated break in the primary system. 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 internal 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, noncondensible gasses in the drywell are 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 primary system 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 I 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 internal 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. Internal (suppression chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary. The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 0.5 psid (Ref. 1). Additionally, 1 of the 7 internal vacuum breakers is assumed to fail 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 setting is a result of the requirement placed on the vacuum breakers to prevent excessive water-level variations in the submerged portion of the vent downcomer lines. The vacuum breaker capacity, with one of the valves failed, is adequate to limit the pressure differential between the suppression chamber and the drywell during post accident drywell cooling operations to a valve that is within the suppression chamber design values. The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Only 6 of the 7 vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers, however, are required to be closed (except during

(continued)

BASES

LCO (continued)

testing, inerting or de-inerting containment or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. 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, Containment Spray System operation may be desirable to mitigate the effects of a DBA. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3, when the Containment Spray System may be operated, to mitigate the effects of inadvertent actuation of the Containment Spray System.

Also, in MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, 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 noncondensible gases 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.

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.

(continued)

BASES (continued)

ACTIONS

A.1

With one of the required vacuum breakers inoperable for opening (e.g., the 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 five OPERABLE vacuum breakers 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 could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one of the six required vacuum breakers inoperable, 72 hours is allowed to restore at least one of the inoperable vacuum breakers 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.

B.1

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker 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 drywell to suppression chamber differential pressure of 0.5 psid is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test.

C.1 and C.2

If the inoperable suppression chamber-to-drywell vacuum breaker cannot be closed or 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

(continued)

BASES

ACTIONS

C.1 and C.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 3.6.1.7.1

Each vacuum breaker is verified closed (except when performing its intended function as stated in LCO 3.6.1.7) 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 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. Each vacuum breaker is equipped with two closed position indicators. One position indicator indicating closed is sufficient to verify the vacuum breaker is closed. However, if one closed position indicator is found to be inoperable, actions should be initiated to restore it to OPERABLE status, if possible. 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.

A Note is added to this SR which 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.

SR 3.6.1.7.2

Each required 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.1.7.2 (continued) 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, since they are located in a harsh environment (the suppression chamber airspace). SR 3.6.1.7.3 Verification of the vacuum breaker opening setting is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.5 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. 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. UFSAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges or from Design Basis Accidents (DBAs). 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 maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from steam exhaust lines in the turbine driven systems (i.e., the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System). 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 – the original limit for the end of a LOCA blowdown was 170°F, based on the Bodega Bay and Humboldt Bay Tests; and,

b. Primary containment peak pressure and temperature – design pressure is 56 psig and design temperature is 281°F (Ref. 1).

(continued)

BASES (continued)

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 pool temperature analyses required by Reference 3). An initial pool temperature of 95°F is assumed for the Reference 1 and Reference 2 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool 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 unit testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

A limitation on the suppression pool average temperature is required to provide assurance that the 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:

a. Average temperature ≤ 95°F when any OPERABLE intermediate range monitor (IRM) channel is > 25/40 divisions of full scale on Range 7 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 when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7 and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit 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 ≤ 95°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 95°F is short enough not to cause a significant increase in plant risk.

(continued)

BASES

LCO (continued)

c. Average temperature ≤ 110°F when all OPERABLE IRM channels are ≤ 25/40 divisions of full scale on range 7. 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.

Note that 25/40 divisions of full scale on IRM Range 7 while not the only indication available, was chosen as a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP. At this power level, heat input is approximately equal to normal system heat losses, i.e., the "point of adding heat".

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 THERMAL POWER is > 1% RTP, the initial conditions exceed the conditions assumed for the Reference 1, 2, and 4 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those 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 average temperature to be restored below the limit. Additionally, when suppression pool temperature is > 95°F, increased monitoring of the suppression pool temperature is required to ensure that it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room 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, the power must be reduced to < 25/40 divisions of full scale on Range 7 for all OPERABLE IRMs within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be > 95°F when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7 and when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2, and D.3

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. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown position is permitted by the definition of an Immediate Completion Time. Further cooldown to Mode 4 is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when suppression 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.

(continued)

BASES

ACTIONS

D.1, D.2 and D.3 (continued)

Given the high suppression pool average 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 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 at ≤ 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 at least 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.

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure post-LOCA. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk and local Suppression Pool temperatures could be exceeded very quickly and possibly exceed the allowable loads on the Torus.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1 (continued)

The 5 minute Frequency during testing is justified by the rates at which tests 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 to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. UFSAR, Section 6.2.
2. NEDC-22082-P, DAEC Suppression Pool Temperature Response.
3. NUREG-0783.
4. DAEC Plant Unique Analysis Report (PUAR), June 1983.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from Safety/Relief Valve (SRV) discharges or from a Design Basis Accident (DBA). 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, which ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the steam exhaust lines in the turbine driven systems (i.e., High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System) and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 58,900 ft^3 at the low water level limit of 10.11 ft and 61,500 ft^3 at the high water level limit of 10.43 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 SRV T-quenchers, vent system downcomer pipes, or HPCI and RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate Net Positive Suction Head (NPSH) to the Emergency Core Cooling System Pumps. 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 SRV discharges and excessive pool swell loads during a 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.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to SRV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid. Suppression pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	A limit that suppression pool water level be ≥ 10.11 ft and ≤ 10.43 ft is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation. The level requirements also ensure that downcomer submergence is sufficient to ensure condensation effectiveness and prevent steam bypass to the suppression chamber air space and that loads and structural integrity are acceptable.
APPLICABILITY	In MODES 1, 2, and 3, a DBA would cause significant loads on the 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. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS-Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as vent system downcomer pipes are covered, HPCI and RCIC turbine exhausts are covered, and SRV T-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. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within 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 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 of this SR was developed considering operating experience related to trending variations in suppression pool water level and water level instrument drift during the applicable MODES and to assessing the proximity to the specified LCO level limits. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms,

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 (continued) to alert the operator to an abnormal suppression pool water level condition.
REFERENCES	1. UFSAR, Section 6.2.

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 (SPC) System can be used to remove 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-SPC subsystem contains two RHR pumps and one heat exchanger and is manually initiated and independently controlled. The two subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. RHR 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 pump in one subsystem is sufficient to meet the overall DBA pool cooling requirement for Loss of Coolant Accidents (LOCAs)(Ref. 1). However, transient events such as a turbine trip or stuck open Safety Relief Valve (SRV) may result in local suppression pool water temperatures that approach the local temperature limit of 200.2°F. An analysis that was performed to verify that the suppression pool temperature limits imposed by NUREG-0783 are not exceeded contained an assumption that one RHR loop was in operation, with 2 RHR pumps operating to provide a total of 9600 gpm of suppression pool cooling flow. This 9600 gpm flow provided a high level of suppression pool mixing, thus limiting the degree of local water temperature deviation from bulk average water temperature. As a result, two RHR pumps are required to support Operability of a RHR Suppression Pool Cooling subsystem (Ref. 3). SRV leakage and High Pressure

(continued)

BASES

BACKGROUND (continued)	Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) 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 during or 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 suppression pool temperature is calculated to remain below the design limit. The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
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 design limits (Ref. 1) and to ensure that local suppression pool temperature limits are not exceeded during limiting transients such as a stuck open relief valve (Ref. 3). 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 both of the RHR pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause 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

(continued)

BASES

APPLICABILITY (continued)

Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.

ACTIONS

A.1

With one RHR pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this Condition, the remaining OPERABLE RHR pumps are adequate to perform the RHR Suppression Pool Cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in the system capacity being less than that assumed in the safety analysis (i.e., the valve won't open in the OPERABLE subsystem) for RHR Suppression Pool Cooling capability. The 30 day Completion Time is based on the remaining RHR-SPC heat removal capability and the low probability of a DBA with concurrent worst case single failure.

B.1

With one RHR pump inoperable in each RHR Suppression Pool Cooling subsystem, if no additional failures occur in the RHR Suppression Pool Cooling System, then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA or following any transient that results in a suppression pool temperature rise. However, an additional single failure in the RHR System could reduce the system capacity below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the remaining RHR-SPC heat removal capability and on engineering judgment, considering the level of redundancy provided.

C.1

With one RHR suppression pool cooling subsystem inoperable for reasons other than Condition A (e.g., both pumps inoperable or flowpath inoperable), the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR suppression pool cooling

(continued)

BASES

ACTIONS

C.1 (continued)

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.

D.1

With two RHR suppression pool cooling subsystems inoperable for reasons other than Condition B (e.g., both subsystems with an inoperable flowpath, or one subsystem with two inoperable pumps and one subsystem with one inoperable pump), 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 because alternative methods to remove heat from primary containment are available.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying by administrative means the correct alignment for manual, power operated and automatic 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 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 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 manual valves or 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 3.6.2.3.2

Verifying that each RHR pump develops a flow rate ≥ 4800 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 and the local suppression pool temperature can be maintained below design limits. This test also verifies that pump performance has not degraded during the surveillance interval. Flow is a normal test of centrifugal pump performance required by ASME Code, Section XI (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice testing confirms component OPERABILITY, trends performance, and detects incipient failures by indicating abnormal performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.2.3.2 (continued) The Frequency of this SR is in accordance with the Inservice Testing Program.
REFERENCES	1. UFSAR, Section 6.2.1.3.3.2. 2. ASME, Boiler and Pressure Vessel Code, Section XI. 3. NEDC-22082-P, DAEC Suppression Pool Temperature Response.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

BASES

BACKGROUND

The suppression pool is designed to absorb the sudden input of heat from the primary system from a Design Basis Accident (DBA) or a rapid depressurization of the reactor pressure vessel (RPV) through the Safety Relief Valves. The primary means provided to remove heat from the suppression chamber is the RHR Suppression Pool Cooling System. Steam blowdown from a DBA can bypass the suppression pool and end up in the suppression chamber airspace as a result of the allowable leakage between the Drywell and Suppression Chamber. Although not required by the accident analysis to ensure that the suppression chamber remains within the analyzed design pressure and temperature limits, condensing the steam in the suppression chamber airspace reduces the long-term pressure response in the primary containment. This support function is provided by two redundant 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 two RHR pumps, which are manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool through the associated piping and returning it to a common suppression pool spray sparger. 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. Thus, both suppression pool cooling (if the RHR heat exchangers and the RHR Service Water System are operated) and suppression pool spray (performed by the spray headers) functions are 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. These analyses demonstrate that the pressure reduction capacity of the RHR Suppression Pool Spray System is not required 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 even without the use of RHR Suppression Pool Spray.

The RHR Suppression Pool Spray is retained in the conversion from the DAEC Technical Specifications to the Improved Technical Specifications (ITS)(see Reference 2), because this function was found to satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii) during the development of NUREG-1433.

LCO

One RHR suppression pool spray subsystem should be available to assist with any potential bypass leakage (Ref. 1). To ensure that this back-up capability is available, two RHR suppression pool spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, at least one subsystem will be OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one of the pumps and associated piping (including spargers), valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, the reactor is pressurized and 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.

(continued)

BASES (continued)

ACTIONS

A.1

With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RHR suppression pool spray subsystem is still available as a back-up to assist with any primary containment bypass leakage. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced capability. The 30 day Completion Time was chosen in light of the back-up nature of this function, the redundant RHR suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of an event 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 loss of the back-up capability to deal with any primary containment bypass leakage. The 8 hour Completion Time is based on this loss of back-up capability and is considered acceptable due to the low probability of an event and because the primary methods to remove heat from primary containment are still available.

C.1 and C.2

If the inoperable RHR suppression pool spray subsystem 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 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying that the spray header and nozzles are unobstructed assures that the suppression pool airspace can be sprayed when desired. An air test is specified as this test is generally performed on both the drywell and suppression pool spray nozzles at the same time and it is not desirable to spray water into the drywell, due to the adverse impact on equipment located there.

Operating experience has shown that these components usually pass the SR when performed at the 60 month Frequency. Therefore, the Frequency was concluded to be acceptable from the reliability standpoint.

REFERENCES

1. UFSAR, Section 6.2.

2. NG-98-0342, J. Franz (IES) to U.S. NRC, "Request for Technical Specification Change (RTS-291): Revision E to the Duane Arnold Energy Center Improved Technical Specifications," February 26, 1998.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Containment Atmosphere Dilution (CAD) System

BASES

BACKGROUND

The CAD System functions to maintain postulated combustible gas concentrations within the primary containment at or below the flammability limits following a Loss of Coolant Accident (LOCA) by diluting hydrogen and oxygen with nitrogen. To ensure that a combustible gas mixture does not occur, oxygen concentration is kept < 5.0 volume percent (v/o).

The CAD System is manually initiated and consists of a nitrogen storage bank and two independent, 100% capacity nitrogen injection subsystems. Each nitrogen injection subsystem includes the pressure regulating valves, control valves and connected piping necessary to transport nitrogen from the storage bank to the drywell and suppression chamber volumes. CAD System OPERABILITY is not affected by the inability of the pressure regulators to regulate pressure, because regulator failure does not affect the CAD Systems ability to inject the required volume of nitrogen into the containment. The failure of the pressure regulators does not result in any piping being subjected to a pressure greater than design. The nitrogen storage bank contains ≥ 50,000 scf, which is adequate for 7 days of CAD System operation. The nitrogen cylinders that make up the storage bank, and the header up to the first normally closed valve in each of the redundant supply lines constitute a "passive" system and, accordingly, are not subject to the single failure criterion that applies only to "active" components. Therefore, it is not necessary that the CAD nitrogen storage bank be redundant.

The CAD System would typically be operated to add nitrogen in a step-wise fashion to dilute combustible gases. After approximately 35 days, containment pressure buildup may be sufficient to require venting.

APPLICABLE SAFETY ANALYSES

To evaluate the potential for hydrogen and oxygen accumulation in primary containment following a LOCA, hydrogen and oxygen generation is calculated (as a function of time following the initiation of the accident). The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

conservative assumptions stated in Reference 1 are used to maximize the amount of hydrogen and oxygen generated. The calculation confirms that when the CAD system is actuated within 3.5 days after a LOCA, the peak oxygen concentration in primary containment is < 5.0 v/o (Ref. 2).

Hydrogen and oxygen may accumulate within primary containment following a LOCA as a result of:

a. A metal water reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

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

LCO

The CAD System must be OPERABLE. The CAD System is considered to be OPERABLE if nitrogen can be injected into both the drywell and suppression chamber volumes via any combination of components in either nitrogen injection subsystem (i.e., the CAD System is considered to be OPERABLE if one nitrogen injection subsystem is capable of injecting into the drywell and the other nitrogen subsystem is capable of injecting into the suppression chamber volume). This ensures operation of the CAD System in the event of an accident of sufficient magnitude to generate hydrogen in significant amounts. Operation of the CAD System is designed to maintain primary containment post-LOCA oxygen concentration < 5.0 v/o for 7 days.

APPLICABILITY

In MODE 1, the CAD System is required to maintain the oxygen concentration within primary containment below the flammability limit of 5.0 v/o following a LOCA. The CAD System is not capable of inerting the containment from normal atmospheric concentration levels; it can only dilute the oxygen concentration to below the flammability limit once an inerted atmosphere has been initially established by

(continued)

BASES

APPLICABILITY (continued)

other means. Because the system is not capable of performing its intended safety function, i.e., it is not OPERABLE, until an inerted atmosphere has been established, the Mode 1 APPLICABILITY has been modified to allow the LCO to not be entered until the Primary Containment has been inerted per LCO 3.6.3.2, "Primary Containment Oxygen Concentration". This ensures that the relative leak tightness of primary containment is adequate and prevents damage to safety related equipment and instruments located within primary containment. In MODE 3, both the hydrogen and oxygen production rates and the total amounts produced after a LOCA would be less than those calculated utilizing the conservative assumptions contained in Ref. 1. Thus, if the analysis were to be performed starting with a LOCA in MODE 3, the time to reach a flammable concentration would be extended beyond the time conservatively calculated for MODES 1 and 2. The extended time would allow hydrogen removal from the primary containment atmosphere by other means and also allow repair of an inoperable nitrogen injection subsystem, and/or nitrogen storage bank, if CAD were not available. Therefore, the CAD System is not required to be OPERABLE in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations of these MODES. Therefore, the CAD System is not required to be OPERABLE in MODES 4 and 5.

ACTIONS

A.1

With the CAD System inoperable, the CAD System must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the availability of other hydrogen mitigating systems.

(continued)

BASES

ACTIONS (continued)

B.1

If any Required Action cannot be met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status,the plant must be brought to at least MODE 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

Verifying that there is ≥ 50,000 scf of nitrogen supply in the CAD System will ensure at least 7 days of post-LOCA CAD operation. This minimum volume of nitrogen allows sufficient time after an accident to replenish the nitrogen supply for long term inerting. This is verified every 31 days to ensure that the system is capable of performing its intended function when required. The 31 day Frequency is based on operating experience, which has shown 31 days to be an acceptable period to verify the nitrogen supply and on the availability of other hydrogen mitigating systems.

SR 3.6.3.1.2

Verifying by administrative means the correct alignment for manual, power operated and automatic valves necessary to establish CAD System OPERABILITY requires the valves necessary to allow nitrogen injection into both the drywell and suppression chamber volumes via any combination of components in either nitrogen injection subsystem to be in the correct position. This provides assurance that the proper flow paths 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.2 (continued)

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 because the CAD System 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 manual valves or 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, improper valve position would only affect a single nitrogen injection subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system.

REFERENCES

1. Safety Guide No. 7.
2. UFSAR, Section 6.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

Nuclear power plants must be 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 in Mark I Containment 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 Containment Atmosphere Dilution System (LCO 3.6.3.1, "Containment Atmosphere Dilution (CAD) System") to provide redundant and diverse methods to mitigate events that produce hydrogen. For example, a postulated event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 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 CAD System dilutes 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. Although the amount of hydrogen generated as a result of a DBA LOCA with successful ECCS mitigation is < 1%, large amounts of hydrogen generation (i.e.: ≈ 5%) are postulated to occur in accordance with Safety Guide 7. 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,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	is diluted and removed by the CAD System more rapidly than it is produced. Primary containment oxygen concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen 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. 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 is low and the primary containment need not be inerted. Furthermore, the probability of an event that generates significant amounts of 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. During reactor startups, a convenient and conservative start time for reducing primary containment oxygen concentration to less than 4.0 v/o within 24 hours occurs when the mode switch is placed in Run. Similarly, during reactor shutdowns, limiting the time oxygen can exceed 4.0 v/o to 24 hours prior to taking the mode switch out of Run is also conservative.

(continued)

BASES (continued)

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 mitigating systems (e.g., the CAD System) and the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

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 inert 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 (control room alarms for containment high oxygen concentration, excessive cycling of the Containment Nitrogen Makeup System or unexplained changes in containment pressure). Indication of abnormal conditions would lead to more frequent monitoring of primary containment oxygen concentration. Also, this Frequency has been shown to be acceptable through operating experience.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SBGT) 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 is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. 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/Dampers (SCIV/Ds)," and LCO 3.6.4.3, "Standby Gas Treatment (SBGT) System."

APPLICABLE SAFETY ANALYSES

There are two DBAs for which credit is taken for secondary containment OPERABILITY. These are a Loss of Coolant Accident (LOCA) (Ref. 1) and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis and that fission

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

products entrapped within the secondary containment structure will be treated by the SBGT System prior to discharge to the environment.

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

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

A.1

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

(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 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 the 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.

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2 or 3, 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

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, 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 and SR 3.6.4.1.2

Verifying that secondary containment equipment hatches (e.g., the Refueling Floor roof hatch and the HPCI/RCIC room roof hatches) and that either the outer door(s) or the inner door(s) 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. Maintaining secondary containment OPERABILITY requires verifying that either the outer door(s) or the inner door(s) in each access opening are closed. However, each secondary containment access door is normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access. 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 (alarmed security/secondary containment doors, frequent plant tours by operations and security personnel and unexplained drops in reactor building to outside atmosphere differential pressure while secondary containment is isolated with SBGT in service). SR 3.6.4.1.2 is modified by a Note that applies to doors 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. Therefore, the probability of misalignment of these doors, once they have been verified to be in the proper position, is low.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.3

The SBGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. SR 3.6.4.1.3 demonstrates that one SBGT subsystem can maintain ≥ 0.25 inches of vacuum water gauge under calm wind conditions (i.e. less than 15 mph wind speed) at a flow rate ≤ 4000 cfm. This cannot be accomplished if the secondary containment boundary is not intact. Therefore, this test is used to ensure secondary containment boundary integrity. Since this SR is a secondary containment test, it need not be performed with each SBGT subsystem. The SBGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SBGT subsystem will perform this test, and also to ensure that the secondary containment remains sufficiently leak tight, even with a worst case single failure present (i.e., a lockout relay failure that results in either all of the inboard or all of the outboard SCIV/Ds failing to close). Operating experience has shown 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.

REFERENCES

1. UFSAR, Section 15.6.6.
2. UFSAR, Section 15.7.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves/Dampers (SCIV/Ds)

BASES

BACKGROUND

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

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

Automatic SCIV/Ds close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or which are related during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment.

Two barriers are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation and possibly loss of secondary containment OPERABILITY.

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

BASES (continued)

APPLICABLE SAFETY ANALYSES

The SCIV/Ds 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 inside secondary containment (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIV/Ds is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SBGT) System before being released to the environment.

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

SCIV/Ds satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

SCIV/Ds form a part of the secondary containment boundary. The SCIV/D 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. A controlled list of Secondary Containment Automatic Isolation Valves/Dampers covered by this LCO, along with their associated stroke times, are listed in Plant Administrative Procedures.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIV/Ds are de-activated and secured in their closed position, and blind flanges are in place. A blind flange (e.g. - a utility penetration) may be opened, in accordance with applicable administrative procedures, if the secondary containment negative pressure surveillance is performed with an equivalent (or larger) penetration open, with secondary containment still considered OPERABLE.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIV/Ds 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 SCIV/Ds OPERABLE is not required in MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during Operations with a Potential for Draining the Reactor Vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. Moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. For isolation devices requiring local operation, these 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. For isolation devices that can be operated remotely from the control room, the isolation device handswitch is tagged per plant procedures, identifying that the isolation device is open under administrative control and must be closed should an isolation signal occur. In the event of an isolation signal, plant procedures direct control room operators to verify all automatic actions occur, and to manually initiate those automatic actions that should have occurred but did not. This will ensure the control room operators verify any isolation devices open under administrative control close in response to an isolation signal. If any of the open isolation devices are unable or fail to close automatically, the control room operators will manually close them.

Note 1 also expands upon the allowance of LCO 3.0.5, which would only allow the penetration to be opened for testing, by allowing the penetration to be opened for other operational reasons, such as draining, venting, etc.

(continued)

BASES (continued)

ACTIONS (continued)

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/D. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIV/Ds 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/D.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV/D 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 criterion are a closed and de-activated automatic SCIV/D, a closed manual valve, or 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 that meets the applicable engineering design requirements, such as seismic. The 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 probability of a DBA, which requires the SCIV/Ds to close, occurring during this short time is very low.

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 appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 devices located in high radiation areas and allows them to be verified 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, once they have been verified to be in the proper position, is low.

B.1

With two SCIV/Ds 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, or a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIV/Ds to close, occurring during this short time, is very low.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves/dampers. This clarifies that only Condition A is entered if one or more penetration flow paths with one SCIV/D is inoperable.

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

(continued)

BASES (continued)

ACTIONS

C.1 and C.2 (continued)

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 are not 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, actions 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.

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, 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 fuel 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

Verifying that the isolation time of each power operated automatic SCIV/D is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV/D 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.2

Verifying that each automatic SCIV/D closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or which are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment. This SR ensures that each automatic SCIV/D will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 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. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 15.6.6.

2. UFSAR, Section 15.7.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SBGT) System

BASES

BACKGROUND

The SBGT System is required by the UFSAR (Ref. 1). The function of the SBGT 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 SBGT 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 demister or moisture separator;

b. An electric heater;

c. A prefilter;

d. A High Efficiency Particulate Air (HEPA) filter;

e. A charcoal adsorber;

f. A second HEPA filter; and

g. A centrifugal fan.

HEPA filters are installed before and after the charcoal adsorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment. The in-place testing of the HEPA filters and charcoal adsorbers is performed under the DAEC Ventilation Filter Testing Program (ITS 5.5.7). If the efficiencies of the HEPA filters and charcoal adsorbers are as specified, the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed, as the UFSAR Section 15.6.6 for the loss-of-coolant accident shows compliance with

(continued)

BASES

BACKGROUND (continued)

10 CFR 100 guidelines with an assumed efficiency of 99% for the adsorber. Operation of the fans significantly different from the design flow envelope will change the removal efficiency of the HEPA filters and charcoal adsorbers.

The sizing of the SBGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. The internal pressure of the SBGT System boundary region is maintained at a negative pressure of at least 0.25 inches water gauge (as determined by averaging pressure readings from different faces of the Secondary Containment boundary) when the system is in operation, which represents an internal pressure that ensures zero exfiltration of air from the building when exposed to calm wind conditions (< 15 mph). Maintaining a negative pressure of 0.25 inches water gauge under calm wind conditions ensures a negative pressure under worst case conditions. Therefore, a negative pressure of 0.25 inches water gauge includes some margin to a negative pressure that ensures zero exfiltration.

The demister 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 removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SBGT System automatically starts and operates in response to secondary containment isolation actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both charcoal filter train fans start. Upon verification that both subsystems are operating, the redundant subsystem is normally shut down.

APPLICABLE SAFETY ANALYSES

The design basis for the SBGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Ref. 3). For all events analyzed, the SBGT subsystem is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

released to the environment. Only one of the two SBGT subsystems is needed to clean up the reactor building atmosphere upon containment isolation.

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

LCO

Following a DBA, a minimum of one SBGT 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 SBGT 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, SBGT 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 SBGT System in OPERABLE status 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

A.1

With one SBGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status in 7 days. In this Condition, the remaining OPERABLE SBGT 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

(continued)

BASES

ACTIONS

A.1 (continued)

availability of the OPERABLE redundant SBGT subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SBGT 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 SBGT subsystem should immediately be placed in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, 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 plant in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must immediately be suspended. Suspension of these activities must not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

LCO 3.0.3 is not applicable 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 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 SBGT subsystems are inoperable in MODE 1, 2, or 3, the SBGT 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 SBGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

LCO 3.0.3 is not applicable in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, 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

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

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 3.6.4.3.1

Operating each SBGT subsystem ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure, 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 is sufficient to ensure potential moisture build-up does not impact the adsorption and filtering function. The 31 day Frequency was also developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system, however these components are not the most-limiting for overall system reliability at this SR Frequency. It is not necessary to run the system for the full 10 hours to demonstrate Operability following maintenance, if that maintenance did not affect the filters and charcoal beds.

SR 3.6.4.3.2

This SR verifies that the required SBGT filter testing is performed in accordance with Specification 5.5.7, Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow capability, 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.

A Note has been added to this SR delaying the entry into associated Conditions and Required Actions for up to one hour. This is necessary because, due to a cross-tie duct between the two SBGT subsystems, the flow path through the SBGT subsystem not being tested must be isolated, making it inoperable, to establish conditions necessary to ensure the tested SBGT subsystem meets the filter train differential

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.2 (continued)

pressure requirements of the VFTP. During the testing, the ability to draw a vacuum on Secondary Containment is maintained by the subsystem under test. One hour minimizes the amount of time the SBGT subsystem is inoperable while providing enough time to perform the required testing. Additionally, LCO 3.0.5 provides allowances for post-maintenance testing required to return a SBGT subsystem to Operable status. The allowance provided by the Note avoids potential entry into LCO 3.0.3 (Condition D) during required routine surveillances and during demonstration of Operability for a previously inoperable subsystem under LCO 3.0.5.

SR 3.6.4.3.3

This SR verifies that each SBGT subsystem starts on receipt of an actual or simulated initiation signal. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR verifies that the filter cooler bypass damper can be opened and the fan started. This ensures that the ventilation mode of SBGT System operation is available. This Surveillance can be performed with the reactor at power and operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 3.1.2.4.12.
2. UFSAR, Section 6.5.3.3.
3. UFSAR, Section 6.2.3.

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, two 2400 gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Although the RHRSW pumps are rated at 2400 gpm, the DAEC has been evaluated to require only 2040 gpm per pump (Ref.5). Either of the two subsystems is capable of providing the required cooling capacity with two pumps operating to maintain safe shutdown conditions (Ref. 6). The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the UFSAR, Section 9.2.3.2, Reference 1.

Cooling water is pumped by the RHRSW pumps from the pump house through the tube side of the RHR heat exchangers, and discharges to either the Cooling Towers or the Cedar River.

The system is initiated manually from the control room. If operating during a Loss of Coolant Accident (LOCA), the system is automatically tripped to allow the diesel generators to automatically power only essential equipment needed to initially mitigate the accident (i.e., within the first 10 minutes). The system can be manually started any time the LOCA signal is manually overridden or clears and when sufficient load carrying capacity exists on the associated diesel generator when offsite power is not available. In any case, RHRSW System operation is not required anytime sooner than 10 minutes after a LOCA.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA and during limiting transients such as stuck open relief valves. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is discussed in the UFSAR, Section 6.2.1.3 and Chapter 15 (Refs. 2 and 3, respectively). These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The safety analyses for long term cooling were performed for various combinations of RHR System failures. The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. As discussed in the UFSAR, Section 6.2.1.3.3.2 and 6.2.1.3.3.3 (Ref. 4) for these analyses, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 10 minutes after a DBA. The RHRSW flow assumed in the analyses is 2040 gpm per pump with two pumps operating in one loop. In this case, the maximum suppression chamber water temperature and pressure are 200°F and 23.6 psig, respectively, which are below the maximum allowable temperature of 340°F and maximum allowable pressure of 62 psig. Similarly, an analysis of the most limiting transient (a stuck open relief valve) indicates that peak local suppression pool temperature does not exceed 194°F, which is below the limit of 200°F.

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

LCO

Two RHRSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.

An RHRSW subsystem is considered OPERABLE when:

(continued)

BASES

LCO (continued)

a. Two pumps are OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the pump house and transferring the water to the RHR heat exchangers at the assumed flow rate.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head is bounded by the River Water Supply pump requirements (LCO 3.7.2, "River Water Supply (RWS) System and Ultimate Heat Sink (UHS)").

APPLICABILITY

In MODES 1, 2, and 3, the RHRSW System is required to be OPERABLE to support the OPERABILITY of the RHR System for primary containment cooling (LCO 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling,") and decay heat removal (LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"). The Applicability is therefore consistent with the requirements of these systems.

In MODES 4 and 5, the OPERABILITY requirements of the RHRSW System are determined by the systems it supports, and therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the RHR Shutdown Cooling System (LCO 3.4.8, "RHR Shutdown Cooling System-Cold Shutdown," LCO 3.9.7, "RHR-High Water Level," and LCO 3.9.8, "RHR-Low Water Level"), which require portions of the RHRSW System to be OPERABLE, will govern RHRSW System requirements during operation in MODES 4 and 5.

ACTIONS

A.1

With one RHRSW pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE RHRSW pumps are adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced RHRSW capability. The 30 day Completion Time is based on the remaining RHRSW heat removal capability and the low probability of a DBA with concurrent worst case single failure.

(continued)

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one RHRSW pump is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA and the redundancy of the remaining portions of the system.

B.1

With one RHRSW pump inoperable in each subsystem, if no additional failures occur, then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA. However, an additional single failure in the RHRSW System could reduce the system capability below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time for restoring one inoperable RHRSW pump to OPERABLE status is based on engineering judgment, considering the level of redundancy provided.

C.1

Required Action C.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. With the unit in this condition, the remaining OPERABLE RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem could result in loss of RHRSW function. The Completion Time is based on the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring RHRSW during this period.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem.

(continued)

BASES

ACTIONS

C.1 (continued)

This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1

With both RHRSW subsystems inoperable for reasons other than Condition B (e.g., both subsystems with inoperable flow paths, or one subsystem with an inoperable pump and one subsystem with an inoperable flow path), the RHRSW System is not capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time for restoring one RHRSW subsystem to OPERABLE status, is based on the Completion Times provided for the RHR suppression pool cooling function.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7, be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

E.1 and E.2

If the RHRSW subsystems cannot be restored to OPERABLE status within the associated Completion Times, 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 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verifying the correct alignment for each power operated and automatic valve in each RHRSW subsystem flow path provides assurance that the proper flow paths will exist for RHRSW

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

operation by ensuring valves are not inadvertently mispositioned. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be realigned to its accident position. This is acceptable because the RHRSW System is a manually initiated system.

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 manual valves or to valves that cannot be inadvertently misaligned, such as check valves. This SR is considered met for OPERABLE valves that are temporarily placed in a position other than the standby readiness position under appropriate administrative and procedural controls. The administrative and procedural controls (such as positioning during a Surveillance Test Procedure or operating in accordance with an approved Operating Instruction) ensure the Operators are cognizant of valve positions and ensure valves are promptly returned to the standby readiness position when the evolution is completed.

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

REFERENCES

1. UFSAR, Section 9.2.3.2.
2. UFSAR, Section 6.2.1.3.
3. UFSAR, Chapter 15.
4. UFSAR, Section 6.2.1.3.3.2 and 6.2.1.3.3.3.
5. NEDO-22082-P, DAEC Suppression Pool Temperature Response.
6. UFSAR Table 6.2-16.

B 3.7 PLANT SYSTEMS

B 3.7.2 River Water Supply (RWS) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The RWS System is designed to provide cooling water for the Emergency Service Water (ESW) and Residual Heat Removal Service Water (RHRSW) Systems, which provide required support for various systems required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RWS System also provides water to the Circulating Water System to make up for cooling tower evaporative losses, as required, during normal operation. Upon receipt of a Loss of Offsite Power or Loss of Coolant Accident (LOCA) signal, the radwaste dilution/cross-tie valves are closed, if open, the river water makeup valves fail open, and selected pumps are started to ensure adequate delivery of water to the RHRSW/ESW Stilling Basin in the pump house. A two minute delay is implemented if a running RWS pump trips due to a dead supply bus and is subsequently restarted in response to a Loss of Offsite Power or LOCA signal.

The RWS System consists of the UHS and two independent and redundant subsystems. Each of the two RWS subsystems is made up of a header, two 6000 gpm pumps, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to support the required systems with one pump operating. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other system.

Cooling water is pumped from the Cedar River by the RWS pumps to the RHRSW/ESW Stilling Basin in the pump house through the two main headers. From there, the water is either used by the RHRSW and/or ESW Systems, or is supplied to the Circulating Water System to replace evaporation losses from the cooling towers during normal plant operation. Since a common Stilling Basin is fed from either RWS subsystem and is connected to both RHRSW/ESW pump pits, either RWS subsystem can feed both RHRSW/ESW subsystems. The adequacy of the Cedar River as the UHS is discussed in Reference 4. The minimum river level requirement ensures that the minimum required flow rate (13 cubic feet per second) will be available to the RWS pump pits, and that

(continued)

BASES

BACKGROUND (continued)	sufficient suction pressure will be present to allow the RWS pumps to deliver sufficient flow to the pump house stilling basin. The maximum river water temperature ensures that the water available for cooling safety related heat loads can remove heat in the quantities assumed in any safety analyses.
APPLICABLE SAFETY ANALYSES	Sufficient water inventory is available for the RWS System if the Ultimate Heat Sink specification is met. The ability of the RWS System to supply sufficient water to support the RHRSW and ESW Systems in providing long term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the UFSAR (Refs. 1 and 2). These analyses include the evaluation of the long term primary containment response after a design basis LOCA. The ability of the RWS System to supply sufficient makeup water in support of systems that provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 1 and 2. The ability to provide onsite emergency AC power is dependent on the ability of the RWS System to supply sufficient makeup water for use by the ESW System in cooling the DGs. The RWS System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The RWS subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of RWS is required to provide makeup water to support the ESW and RHRSW Systems in providing the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of RWS must be OPERABLE. At least one subsystem will operate if the worst single active failure occurs coincident with the loss of offsite power. A subsystem is considered OPERABLE when it has an OPERABLE UHS, one OPERABLE pump, and an OPERABLE flow path capable of

(continued)

BASES

LCO (continued)

taking suction from the intake structure and transferring the water to the RHRSW/ESW Stilling Basin in the pump house.

The OPERABILITY of the UHS is based on having a minimum river water level of 725.2 ft mean sea level and a maximum river water temperature of 95° F. The minimum river level is based on the minimum level assumed in the RWS System resistance calculations and the maximum river temperature is based on the heat removal calculations for components supported by the RHRSW and ESW Systems.

APPLICABILITY

In MODES 1, 2, and 3, the RWS System and UHS are required to be OPERABLE to support OPERABILITY of the RHRSW and ESW Systems.

In MODES 4 and 5, the OPERABILITY requirements of the RWS 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, LCOs of the systems supported by the RWS System and UHS will govern RWS System and UHS OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

With one RWS subsystem inoperable, the RWS subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE RWS subsystem is adequate to supply sufficient makeup water. However, the overall reliability is reduced because a single failure in the OPERABLE RWS subsystem could result in loss of RWS function.

The 7 day Completion Time is based on the redundant RWS System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable RHRSW or ESW subsystem.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the RWS subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both RSW subsystems are inoperable, or the UHS is determined to be inoperable, 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 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 of Condition B are modified by a Note indicating that the Applicable Condition of LCO 3.4.7 "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," be entered and Required Actions taken if the inoperable RWS subsystem results in an inoperable RHR Shutdown Cooling subsystem. The Note also alerts the operator that RHR shutdown cooling will be inoperable when the Applicability of LCO 3.4.7 is met. This allows the operator to make provisions for an alternate method of decay heat removal for each inoperable RHR shutdown cooling subsystem, in accordance with the Required Actions of LCO 3.4.7. This is in accordance with LCO 3.0.6 and ensures proper actions are taken for these components.

SURVEILLANCE REQUIREMENT

SR 3.7.2.1

This SR verifies the river water level to be sufficient for the proper operation of the RWS pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.2

Verification of the River Water temperature ensures that the heat removal capability of the RHRSW and ESW Systems are within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.2.2 (continued)

trending of the parameter variations during the applicable MODES.

SR 3.7.2.3

Verifying the correct alignment for each power operated and automatic valve in each RWS subsystem flow path provides assurance that the proper flow paths will exist for RWS 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 being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves.

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

SR 3.7.2.4

This SR verifies that the automatic isolation valves of the RWS System will automatically switch to the safety or emergency position to provide cooling water exclusively to the RHRSW/ESW Stilling Basin in the pump house during an accident event. This is demonstrated by the use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of one of the two RWS pumps in each subsystem.

Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 5.4.7.2.2.
2. UFSAR, Section 6.2.2.
3. UFSAR, Section 9.2.2.
4. UFSAR, Section 1.8.27.

B 3.7 PLANT SYSTEMS

B 3.7.3 Emergency Service Water (ESW) System

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the Diesel Generators (DGs), room coolers for Emergency Core Cooling System equipment, Control Building Chillers, and various minor heat loads required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The ESW System also provides cooling to unit components, as desired during normal operation. Upon receipt of a start signal from its associated DG, each ESW pump is automatically started.

The ESW System consists of two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, one 1200 gpm pump, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to support the required systems. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other subsystem. The capability exits to manually cross connect the ESW subsystems using a removable pool piece, however, one ESW pump cannot be used to supply both ESW loops.

Cooling water is pumped from the RHRSW/ESW pump pit in the pump house by the ESW pumps to the essential components through the two main headers. After removing heat from the components, the water is either discharged from the DG directly to a storm sewer, or is combined with water discharged from the RHRSW System and Well Water System and discharged to the Circulating Water System to replace evaporation losses from the cooling towers, or directly to the river via the discharge canal. A complete description of the ESW System is presented in the UFSAR, Section 9.2.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the ESW System to support long term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the UFSAR, Chapter 6 (Ref. 2). These analyses include the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

evaluation of the long term primary containment response after a design basis LOCA.

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in Reference 2. The ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the DGs. The long term cooling capability of the RHR, core spray, and RHR service water pumps is also dependent on the cooling provided by the ESW System, via either motor cooling or room cooling.

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

LCO

The ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of ESW is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two subsystems of ESW must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has one OPERABLE pump and an OPERABLE flow path capable of taking suction from the RHRSW/ESW pump pit in the pump house and transferring the water to the appropriate equipment.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the ESW pumps is ensured to be present by the RWS requirements (LCO 3.7.2, "River Water Supply and Ultimate Heat Sink (UHS)").

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

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the ESW System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the ESW System. Therefore, the ESW System is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the ESW System is determined by the systems if supports, 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 ESW System will govern OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

With one ESW subsystem inoperable, the ESW subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE ESW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ESW subsystem could result in loss of ESW function.

The 7 day Completion Time is based on the redundant ESW System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG.

Required Action A.1 is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources-Operating," LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," be entered and Required Actions taken if the inoperable ESW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

B.1 and B.2

If the ESW subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both ESW subsystems are inoperable the unit must be placed in a MODE in which the LCO does not apply. To achieve this status,

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

Verifying the correct alignment for each power operated, and automatic valve in each ESW subsystem flow path provides assurance that the proper flow paths will exist for ESW operation by ensuring valves are not inadvertently mispositioned. 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 being mispositioned are in the correct position. This SR does not apply to manual valves or to valves that cannot be inadvertently misaligned, such as check valves. This SR is considered met for OPERABLE valves that are temporarily placed in a position other than the standby readiness position under appropriate administrative and procedural controls. The administrative and procedural controls (such as positioning during a Surveillance Test Procedure or operating in accordance with an approved Operating Instruction) ensure the Operators are cognizant of valve positions and ensure valves are promptly returned to the standby readiness position when the evolution is completed.

This SR is modified by a Note indicating that isolation of the ESW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ESW System. As such, when all ESW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the ESW System is still OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 (continued)

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

SR 3.7.3.2

This SR verifies the automatic start capability of the ESW pump in each subsystem. This is demonstrated by the use of an actual or simulated initiation signal.

Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.2.3.
2. UFSAR, Chapter 6.

B 3.7 PLANT SYSTEMS

B 3.7.4 Standby Filter Unit (SFU) System

BASES

BACKGROUND

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

The safety related function of the SFU System includes two independent and redundant high efficiency air filtration subsystems for emergency treatment of outside supply air. Each subsystem consists of a demister, an electric heater, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork and dampers. Demisters remove water droplets from the airstream. HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The SFU System is a standby system, parts of which also operate during normal unit operations to maintain the control room environment. Upon receipt of the initiation signal (indicative of conditions that could result in radiation exposure to control room personnel), the SFU System automatically starts and a system of dampers isolates the control building to prevent infiltration of contaminated air into the control room. Outside air is taken in at the normal ventilation intake and is passed through one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles before being mixed with the recirculated air. The air (outside and/or recirculated) is cooled by Air Conditioning (AC) units supplied by the Control Building Chillers (CBCs). The SFUs and AC units share common ductwork such that either SFU may supply outside air to either AC unit. However, the CBCs and AC units are addressed as part of LCO 3.7.5, "Control Building Chiller System."

The SFU System is designed to maintain the control room environment for a 30 day continuous occupancy after a DBA without exceeding 5 rem whole body dose or its equivalent to any part of the body. A single SFU subsystem will

(continued)

BASES

BACKGROUND (continued)

pressurize the control room to ≥ 0.1 inches water gauge pressure above atmospheric pressure, under calm wind conditions (i.e. less than 5 mph wind speed). This will prevent infiltration of air from surrounding buildings. Other areas in the control building that directly communicate with the control room via HVAC system ductwork or doors are also required to maintain a positive pressure relative to the adjacent areas outside the control building. This will assure that leakage is from the control building to the adjacent areas or outdoors. SFU System operation in maintaining control room habitability is discussed in the UFSAR, Sections 6.4 and 9.4.4, (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the SFU System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in the UFSAR, Section 6.4 and Chapter 15 (Refs. 1 and 3, respectively). The SFU System is assumed to operate in the isolation mode following a loss of coolant accident, fuel handling accident, main steam line break, and control rod drop accident. The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 1. No single active failure will cause the loss of control room habitability.

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

LCO

Two redundant subsystems of the SFU 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 SFU 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. Fan is OPERABLE;

(continued)

BASES

LCO (continued)

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

c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the control room boundary must be maintained in a condition sufficiently leak-tight such that the pressurization limit of SR 3.7.4.4 can be met. However, it is acceptable for access doors to be open for normal control room entry and exit and not consider it to be a failure to meet the LCO.

APPLICABILITY

In MODES 1, 2, and 3, the SFU 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 because of the pressure and temperature limitations in these MODES. Therefore, maintaining the SFU 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 Operations with Potential for Draining the Reactor Vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

With one SFU subsystem inoperable, the inoperable SFU subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE SFU subsystem is adequate to perform control room radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced SFU System capability. The 7 day

(continued)

BASES

ACTIONS

A.1 (continued)

Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable SFU subsystem 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 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. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable SFU subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE SFU subsystem may be placed in the isolation mode (i.e., one SFU subsystem in operation with the control building isolated). This action ensures that the remaining 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

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

room. This places the unit in a condition that minimizes risk.

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 the subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

D.1

If both SFU subsystems are inoperable in MODE 1, 2, or 3, the SFU System may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

LCO 3.0.3 is not applicable 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. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two SFU subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, action must be initiated immediately to suspend OPDVRs 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 3.7.4.1

Operating each SFU subsystem for ≥ 15 minutes ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure, can be detected for corrective action. Since the SFU charcoal is tested at a Relative Humidity ≥ 95%, extended operation of the electric heaters is not required. Thus, each subsystem need only be operated for ≥ 15 minutes to demonstrate the function of each subsystem. The function of the SFU electric heaters is to pre-heat incoming air to above 40°F to ensure adsorption occurs within the temperature range that charcoal testing is performed. 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 3.7.4.2

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

SR 3.7.4.3

This SR verifies that on an actual or simulated initiation signal, each SFU subsystem starts and operates. This SR also ensures that the control room isolates. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Standby Filter Unit Instrumentation," overlaps this SR to provide complete

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.3 (continued)

testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.7.4.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the SFU System. During the emergency mode of operation, the SFU System is designed to slightly pressurize the control room ≥ 0.1 inches water gauge above atmospheric pressure, under calm wind conditions (i.e. less than 5 mph wind speed) to prevent unfiltered inleakage. The SFU System is designed to maintain this positive pressure at a flow rate of 1000 cfm ± 10% to the control room in the isolation mode. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration systems SRs.

REFERENCES

1. UFSAR, Section 6.4.
2. UFSAR, Section 9.4.4.
3. UFSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.5 Control Building Chillers (CBC) System

BASES

BACKGROUND

The CBC System provides temperature control for the control building HVAC system under both normal and accident conditions.

The CBC System consists of two independent, redundant subsystems that provide cooling of recirculated control room air. Each subsystem consists of cooling coils, fans, a chiller, a compressor, ductwork, dampers, and instrumentation and controls to provide for control room temperature control. The CBCs receive water from both the ESW System and the Well Water System. Only the ESW System is required by this LCO.

The CBC System is designed to provide a controlled environment under both normal and accident conditions. Because the source of control room air is common with the air distributed to the remainder of the control building, no special means of isolating just the control room is provided. A single subsystem provides the required temperature control to maintain a suitable control building environment. The design conditions for the control room environment are 75°F dry bulb and 50% relative humidity. The CBC System operation in maintaining the control room temperature is discussed in the UFSAR, Section 9.4.4.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CBC System is to maintain the control room temperature for a 30 day continuous occupancy.

The CBC System components are arranged in redundant safety related subsystems. During emergency operation, the CBC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single failure of a component of the CBC 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 temperature control. The CBC-System is designed in-accordance with Seismic

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Category I requirements. The CBC System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

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

LCO

Two independent and redundant subsystems of the CBC 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 CBC System is considered OPERABLE when the individual components necessary to maintain the control building temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls. A CBC is considered inoperable if it trips and cannot be promptly restarted. Therefore, a CBC that spuriously trips and can subsequently be restarted in a reasonable period of time, is not considered inoperable. In addition, during conditions in MODES other than MODES 1, 2, and 3 when the CBC System is required to be OPERABLE (e.g., during CORE ALTERATIONS), the necessary portions of the ESW System, RWS System, and the Ultimate Heat Sink are also required as part of the OPERABILITY requirements covered by this LCO.

APPLICABILITY

In MODE 1, 2, or 3, the CBC System must be OPERABLE to ensure that the control building temperature will not exceed equipment OPERABILITY limits.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident (DBA) are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CBC System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

(continued)

BASES

APPLICABILITY (continued)

a. During Operations with a Potential for Draining the Reactor Vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

With one CBC subsystem inoperable, the inoperable CBC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE CBC subsystem is adequate to perform the control building air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control building air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control building isolation, the consideration that the remaining subsystem 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 CBC subsystem 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 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

(continued)

BASES (continued)

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

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 CBC subsystem may be placed immediately in operation. This action ensures that the remaining 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. This places the unit in a condition that minimizes risk.

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, 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.

D.1

If both CBC subsystems are inoperable in MODE 1, 2, or 3, the CBC 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 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

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

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. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two CBC subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control building. This places the unit in a condition that minimizes risk.

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, 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 3.7.5.1

This SR verifies that the heat removal capability of the system is sufficient to remove available control building heat load. The 92 day Frequency is appropriate since significant degradation of the CBC System is not expected over this time period.

REFERENCES

1. UFSAR, Section 9.4.4.2.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND

During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the 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 moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the 30 minute holdup line.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Steam-Line Break Accident (Roof Top Release). This analysis assumes the concentrations of radionuclides in the reactor water are those associated with an assumed stack gas release limit of 1,000,000 μCi/sec (1.0 Ci/sec)(Ref. 3).

The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Restricting the gross radioactivity rate of noble gases from the main condenser (Ref. 1) provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 (Ref. 2) in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50. The offgas

(continued)

BASES

LCO (continued)

pretreatment radiation monitor indicates in mr/hr. and is set to initiate an alarm if the monitor exceeds a trip setting equivalent to 1.0 Ci/second of noble gases after 30 minutes delay in the offgas holdup lines.

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, 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, 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 steam line rupture.

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

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the 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

(continued)

BASES

ACTIONS

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

power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (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. UFSAR, Section 11.3.3.
2. 10 CFR 100.
3. UFSAR, Section 15.10.3.

B 3.7 PLANT SYSTEMS

B 3.7.7 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 slightly less than 25% 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 two valves connected to the main steam lines at the bypass valve chest, which is between the main steam isolation valves and the turbine stop valve chest. Each of these two valves is 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 UFSAR, Sections 7.7.2.2.1, 10.2.2 and 10.4.4 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct 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 bypass chest, 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 Feedwater Controller Failure - Maximum Demand transient, as discussed in the UFSAR, Section 15.1.1 (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 a MCPR penalty. The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(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 certain events that cause rapid pressurization, so 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 this LCO to be met. The MCPR limits for the inoperable Main Turbine Bypass System are specified in the COLR (separate limits are specified for one valve and both valves inoperable). An OPERABLE Main Turbine Bypass valve 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).

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 transient. As discussed in the Bases for LCO 3.2.2, sufficient margin to these limits exists at < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1 and A.2

If the Main Turbine Bypass System is inoperable (one or both 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 transient. 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 3.7.7.1

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.2

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. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant startup and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

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 UFSAR (Ref. 1). The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Sections 7.7.2.2.1, 10.2.2 and 10.4.4.
2. UFSAR, Section 15.1.1.

B 3.7 PLANT SYSTEMS

B 3.7.8 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 UFSAR, Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in the UFSAR, Section 15.7.1 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. 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 well below the guideline limits of 10 CFR 100 (Ref. 3) and meet the exposure guidelines of NUREG-0800 (Ref. 4). A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in UFSAR, Section 15.7.1.4 (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 no more severe than those of the fuel handling accident over the reactor core, as discussed in the UFSAR, Section 9.1.2.3.3.4 (Ref. 6). 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 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.

APPLICABILITY

This LCO applies during movement of 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 in MODE 4 or 5. However, since irradiated 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 irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

When the initial conditions for an accident cannot be met, action must be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the movement of irradiated fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

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 all water level changes are controlled by unit procedures.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 9.1.2.
2. UFSAR, Section 15.7.1.
3. 10 CFR 100.
4. NUREG-0800, Section 15.7.4, Revision 1, July 1981.
5. UFSAR, Section 15.7.1.4.
6. UFSAR, Section 9.1.2.3.3.4.

B 3.7 PLANT SYSTEMS

B 3.7.9 Control Building/Standby Gas Treatment (CB/SBGT) Instrument Air System

BASES

BACKGROUND

The CB/SBGT Instrument Air System is designed to provide compressed air to support:

- closure of the reactor building-to-suppression chamber vacuum breaker butterfly valves
- leak tightness of the reactor building-to-suppression chamber vacuum breaker butterfly valves (by pressurizing the T-ring seals) when closed
- leak tightness of the primary containment purge system isolation valves (by pressurizing the T-ring seals) when closed
- closure of the drywell cooling water containment isolation valves
- SBGT flow control and filter cooler bypass damper opening
- Standby Filter Unit (SFU) flow control
- ventilation flow path and temperature control for the Control Building Chiller (CBC) System, which is also the ventilation flow path for the SFU System

These systems and components function to limit fission product release and control the environment from the which the unit can be safely operated following a Design Basis Accident (DBA).

The CB/SBGT Instrument Air System consists of two independent and redundant subsystems. Each of the two CB/SBGT Instrument Air subsystems is made up of a compressor, air receiver, associated instrumentation, and piping. The air receivers are normally supplied by the plant instrument air system. If the pressure in the air receiver decreases below 78 psig (nominal), then the CB/SBGT

(continued)

BASES

BACKGROUND (continued)	Instrument Air compressor will automatically start. With the air receiver pressure higher than the plant instrument air system, check valves will close to provide isolation of each CB/SBGT Instrument Air subsystem. Either of the two subsystems is capable of providing compressed air to support the required systems. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other subsystem.
APPLICABLE SAFETY ANALYSES	The ability of the CB/SBGT Instrument Air System to provide compressed air is an implicit assumption in evaluations of the equipment required to limit fission product release and control the environment from which the unit can be safely operated following a DBA. The CB/SBGT Instrument Air System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
LCO	The CB/SBGT Instrument Air subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of CB/SBGT Instrument Air is required to support operation of SBGT, SFU, CBC, and containment isolation assumed in the safety analyses. To ensure this requirement is met, two subsystems of CB/SBGT Instrument Air must be OPERABLE. At least one subsystem will operate if the worst single active failure occurs coincident with the loss of offsite power. The isolation of the CB/SBGT Instrument Air System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the CB/SBGT Instrument Air System.
APPLICABILITY	In MODES 1,2,and 3, the CB/SBGT Instrument Air System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the CB/SBGT Instrument Air System. Therefore, the CB/SBGT Instrument Air System is required to be OPERABLE in these MODES.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the OPERABILITY requirements of the CB/SBGT Instrument Air System are determined by the systems it supports, 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 CB/SBGT Instrument Air System will govern OPERABILITY requirements in MODES 4 and 5.

ACTIONS

A.1

Required Action A.1 is intended to provide assurance that a loss of the plant instrument air system, during the period that a CB/SBGT Instrument Air subsystem is inoperable, does not result in a complete loss of safety function of critical systems.

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

a. An inoperable CB/SBGT Instrument Air subsystem exists; and

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

If, at any time during the existence of this Condition (one CB/SBGT Instrument Air subsystem inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required CB/SBGT Instrument Air subsystem inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE CB/SBGT Instrument Air subsystem 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. Additionally, the 4 hour Completion Time takes in to account the capability of the OPERABLE CB/SBGT Instrument Air subsystem, reasonable

(continued)

BASES

ACTIONS

A.1 (continued)

time for repairs, and low probability of a DBA during this period.

A.2

With one CB/SBGT Instrument Air subsystem inoperable, the CB/SBGT Instrument Air subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE CB/SBGT Instrument Air subsystem is adequate to support the SBGT, SFU, CBC, and containment isolation functions. However, the overall reliability is reduced because a single failure in the OPERABLE CB/SBGT Instrument Air subsystem could result in a loss of the supported functions.

The 7 day Completion Time is based on the redundant CB/SBGT Instrument Air System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occuring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG or ESW subsystem.

B.1 and B.2

If the CB/SBGT Instrument Air subsystem cannot be restored to OPERABLE status within the associated Completion Time or both CB/SBGT Instrument Air subsystems are inoperable, 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 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)

SUREVEILLANCE REQUIREMENTS

SR 3.7.9.1

Operating each CB/SBGT Instrument Air compressor for ≥ 20 minutes allows the oil and other components to reach their operating temperature. This periodic operation removes condensation which may cause rusting in the cylinders, if it were to accumulate. The 31 day Frequency and the operating time are based on vendor recommendations.

SR 3.7.9.2

This SR verifies that each CB/SBGT Instrument Air subsystem has the capability to deliver suffcient quantity of compressed air to support the SBGT, SFU, CBC, and containment isolation functions. This SR takes into account both the compressor capacity and the integrity of the distribution system.

This SR also verifies the automatic start capability of the CB/SBGT Instrument Air compressor in each subsystem. This is demonstrated by the use of an actual or simulated initiation signal.

The 92 day Frequency is consistent with the Frequency for pump testing in accordance with the Inservice Testing Program requirements. Therefore, this Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.3.1.

2. UFSAR, Section 6.2.4.

3. UFSAR, Section 6.2.5.

4. UFSAR, Section 6.5.3.3.

5. UFSAR, Section 6.4.2.

6. UFSAR, Section 9.4.4.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred and alternate perferred), and the onsite standby power sources (Diesel Generators (DGs) 1G-31 and 1G-21). As discussed in UFSAR Section 3.1.2.2.8 (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 via essential buses 1A3 and 1A4.

The Class 1E AC Distribution System is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two preferred offsite power supplies and a single DG.

Offsite power is supplied to the 161 kV and 345 kV switchyards from the transmission network by six transmission lines. The 345 kV switchyard and the 161 kV switchyard are connected via the autotransformer, and both sections of the switchyard are connected to the transmission grid by at least two independent lines. From the 161 kV switchyard (the preferred power source), a single overhead transmission line feeds the startup transformer. From the startup transformer, dual isolated secondary windings provide feeds to the 4160 volt essential buses, 1A3 and 1A4, through separate bus supply lines and circuit breakers. The startup transformer is sized to supply all plant power (both essential and non-essential loads) during unit startup. From the tertiary winding on the autotransformer (the alternate preferred power source), a single 34.5 kV underground line feeds the standby transformer. From the standby transformer, a single 4160 volt line feeds both essential buses through separate bus supply circuit breakers. A detailed description of the offsite power network and circuits to the onsite Class 1E essential buses is found in the UFSAR, Section 8.2 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls

(continued)

BASES

BACKGROUND (continued)

required to transmit power from the offsite transmission network to the onsite Class 1E essential bus or buses. Startup transformer (1X3) provides the normal source of power to the essential buses 1A3 and 1A4. If either 4.16 kV essential bus loses power, an automatic transfer from the startup transformer to the standby transformer (1X4) occurs.

The startup transformer and standby transformer are both sized to accommodate the simultaneous starting of all ESF loads on receipt of an accident signal without the need for load sequencing; however, emergency loads are normally sequenced onto the essential buses regardless of the source of power (onsite or offsite).

The onsite standby power source for 4.16 kV essential buses 1A3 and 1A4 consists of two DGs. DGs 1G-31 and 1G-21 are dedicated to essential buses 1A3 and 1A4, respectively. A DG starts automatically on a Loss of Coolant Accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an essential bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of essential 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 essential bus on a LOCA signal alone. Following the trip of offsite power, non emergency loads powered from essential buses are load shed. When the DG is tied to the essential bus, loads are then sequentially connected to its respective essential bus. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG.

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

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the DGs in the process. Within 25 seconds after the initiating signal is received, all automatic and permanently

(continued)

BASES

BACKGROUND (continued)

connected loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for the DGs satisfy the intent of Safety Guide 9 as discussed in UFSAR Section 1.8.9 (Ref. 3). DGs 1G-31 and 1G-21 have the following ratings:

a. 2850 kW - continuous,

b. 3000 kW - 2000 hours, and

c. 3250 kW - 300 hours.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF Systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF Systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

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

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

b. A worst case single failure.

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

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System and two separate and independent DGs

(continued)

BASES

LCO (continued)

(1G-31 and 1G-21) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an Abnormal Operational Transient or a postulated DBA. Qualified offsite circuits are those that are described in the UFSAR, and are part of the licensing basis for the unit.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the essential buses. The two offsite circuits consist of: 1) the incoming autotransformer (T1) and disconnect (1401, 6782, 2812 or 4731), the incoming circuit breaker (8490) and disconnect (8491), the underground 34.5 kV line, the standby transformer (1X4), the 4160 volt supply line and the two supply circuit breakers (1A301 and 1A401) to essential buses 1A3 and 1A4, respectively, and 2) either the incoming circuit breaker (5550) and disconnects (5551 and 5552) or incoming circuit breaker (5560) and disconnects (5553 and 5555), the overhead 161 kV line, the startup transformer (1X3), the two 4160 volt supply lines and the two supply circuit breakers (1A302 and 1A402) to essential buses 1A3 and 1A4, respectively.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective essential bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the essential buses. Proper sequencing of loads, including non-essential load shedding capability, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one essential bus, with slow transfer capability to the other circuit OPERABLE, and not violate separation criteria.

(continued)

BASES

LCO (continued)

A circuit that is not connected to either essential bus is required to have OPERABLE slow transfer interlock mechanisms to both essential buses to support OPERABILITY of that circuit.

APPLICABILITY

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

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of Abnormal Operational Transients; and

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

The AC power requirements for MODES 4 and 5 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 with one offsite circuit inoperable, 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A.2

The power sources for the plant auxiliary power system are sufficient in number and have adequate electrical and physical independence to ensure that no single probable event could interrupt all auxiliary power at one time. In the condition of one inoperable offsite power source, all essential and non-essential buses remain OPERABLE and the remaining offsite power source continues to provide a highly reliable power source. Required Action A.2 requires restoring the inoperable offsite circuit to OPERABLE status, prior to entering MODE 2 from MODE 3 or 4. The inoperable offsite circuit must be restored to OPERABLE status prior to entering MODE 2 from MODE 3 or 4 to ensure that at least two offsite power sources will be available before the reactor is taken beyond just critical.

Entry into MODE 1 from MODE 2 with an inoperable offsite circuit is acceptable since LCO 3.0.4 allows continued operation of the unit in a MODE or other specified condition in which operation for an unlimited period of time is allowed. The inoperable offsite circuit only has to be repaired prior to entering MODE 2 from MODE 3 or 4.

B.1

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

(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). Failures of "redundant required features" refers to 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 allowable out of service time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division (Division 1 or 2) is inoperable.

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

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

(continued)

BASES

ACTIONS

B.2 (continued)

The remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3

Required Action B.3 requires that the cause of the inoperability be evaluated to ensure a common cause failure does not exist that could render the OPERABLE DG inoperable. This evaluation may be performed by analysis or inspection or by demonstration of OPERABILITY. If the cause of inoperability exists on the other DG, it is declared inoperable upon discovery, and Condition D of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, SR 3.8.1.2 can be performed within the same Completion Time as Required Action B.3 to provide assurance of continued OPERABILITY of the remaining DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing B.3, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

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

(continued)

BASES

ACTIONS (continued)

B.4

To ensure the continued OPERABILITY of the remaining DG during the 7 day Completion Time of Required Action B.5, SR 3.8.1.2 must be performed once per 72 hours for the OPERABLE DG. The 72 hour Completion Time is acceptable since it has already been determined that a common cause failure does not exist.

B.5

In Condition B, the remaining OPERABLE DG and offsite circuit(s) are adequate to supply electrical power to the onsite Class 1E Distribution System. The 7 day 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.

The second Completion Time for Required Action B.5 establishes a limit based on the maximum time allowed for the combination of one DG and two offsite AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO except for Action A. If Condition B is entered while, for instance, two offsite circuits are inoperable and one circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 24 hours. This situation could lead to a total of 8 days, since initial failure of the LCO (except for Condition A), to restore the DG. At this time, the second offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 24 hours (for a total of 9 days) allowed prior to complete restoration of the LCO (except for Condition A). The 8 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 B and C are entered concurrently, and when corrective actions are completed prior to completing the shutdown required by LCO 3.0.3 (which is required to be entered by Action F). The "AND" connector between the 7 day and 8 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

BASES

ACTIONS

B.5 (continued)

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met, instead of the time that Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with inoperability of two offsite circuits. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is 12 hours. When a concurrent redundant required feature failure exists, a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions, (i.e., single division systems are not included in the list). 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 allowable out of service time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All offsite circuits are inoperable; and

b. A required feature is inoperable.

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the Offsite Electrical Power System does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this 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

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 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 in Required Action C.2 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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

The second Completion Time for Required Action C.2 establishes a limit based on the maximum time allowed for the combination of one DG and two offsite AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO except for Condition A. If Condition C is entered while, for instance, one DG is inoperable and the DG is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 8 days, since initial failure of the LCO (except for Condition A), to restore one of the two inoperable offsite circuits. At this time, a DG could again become inoperable, one offsite circuit restored OPERABLE, and an additional 7 days (for a total of 15 days) allowed prior to complete restoration of the LCO (except for Condition A). The 8 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 B and C are entered concurrently, and when corrective actions are completed prior to completing the shutdown required by LCO 3.0.3 (which is required to be entered by Action F). The "AND" connector between the 24 hours and 8 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowable out of service time "clock." This exception results in establishing the "time zero" at the time that the LCO was initially not met (except for condition A), instead of the time that Condition C was entered.

(continued)

BASES

ACTIONS (continued)

D.1

With two DGs inoperable, there is no 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 unit generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation. According to the recommendations contained in Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

E.1 and E.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 at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Condition F 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with UFSAR Section 3.1.2.2.9 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are largely in accordance with the recommendations of Safety Guide 9 as discussed in UFSAR Section 1.8.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10) or as addressed in the UFSAR.

The minimum steady state output voltage of 3744V (i.e., approximately 90% of the nominal 4160 V output voltage) is appropriate to show satisfactory DG operation. This value also provides a large margin of safety since safety related motors are capable of accelerating their loads at 70% of rated voltage. The specified maximum steady state output voltage of 4576 V or 110% of 4160 V appropriately shows satisfactory DG operation and is below the damage curve of 4000 V motors. The DGs are adjustable within the 4160 V ± 10% range. The specified minimum and maximum frequencies of the DG are 59.5 Hz and 60.5 Hz, respectively. These values are approximately equal to ± 1% of the 60 Hz nominal frequency and are conservative with respect to the recommendations found in Regulatory Guide 1.9 (Ref. 17).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 at least the minimum required offsite power supply breakers are in their correct position to ensure that distribution buses and loads are connected to either the preferred power source or the alternate preferred power source and that appropriate independence of offsite circuits is maintained. This can be accomplished by verifying that an essential bus is energized, and that the status of offsite supply breakers that are displayed in the control room are correct. The status of manual disconnects is verified administratively. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help 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, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and (for SR 3.8.1.2 only) followed by a warmup prior to loading. Note 3 to SR 3.8.1.2 allows delaying the entry into associated Conditions and Required Actions for up to two hours during the performance of the conditional surveillance required by Required Actions B.3 or B.4. This Note is necessary because to perform a slow start and warmup of the DG requires reducing the governor control setting to minimum and securing the generator field excitation. The governor control setting is gradually increased to bring the DG to synchronous speed and to allow for warmup. Once the DG is at synchronous speed, the generator field excitation is enabled and the DG is again capable of supplying the essential bus. During this warmup portion of the surveillance test, the DG is incapable of supplying the essential bus and is considered inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

After completion of the SR, the fuel racks to the DG are disabled to allow purging of any residual fuel oil from the cylinders. This also renders the DG inoperable. The two hours allowed by the Note minimizes the amount of time a DG is inoperable while providing enough time to perform the required Conditional Surveillance and avoids entering the shutdown actions of Condition E or F unnecessarily.

For the purposes of this testing, the DGs are manually started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines during testing, the manufacturer of the DGs installed at the DAEC recommends a modified start in which the starting speed of the DG is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2 (SR 3.8.1.2).

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency (i.e. - voltage ≥ 3744 V and frequency ≥ 59.5 Hz) within 10 seconds; and achieves steady state voltage ≥ 3744 V and ≤ 4576 V and frequency ≥ 59.5 Hz and ≤ 60.5 Hz. The 10 second start requirement supports the assumptions in the design basis LOCA analysis of UFSAR, Section 6.3 (Ref. 12) and the accident analysis (Ref. 15). The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Safety Guide 9. The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and can be manually loaded to ≥ 2750 kW and ≤ 2950 kW, providing a 200 kW range centered on the continuous duty rating of the DGs of 2850 kW. This range ensures that the DGs are tested at a load above the maximum expected accident load of 2665 kW. 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 greater than 0.9 lagging. While a value of 0.8 is the design rating of the machine, the machine is operated at power factors greater than 0.9 for normal operations and greater than 0.8 for surveillance testing. The load limit 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 normal 31 day Frequency for this Surveillance is consistent with Safety Guide 9.

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. Similarly, momentary power factor transients above the limit do not invalidate the test.

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 day tank low level alarm is annunciated. This low level alarm should only be received if the automatic fuel oil transfer instrumentation is not functioning properly. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of approximately one hour of DG operation at full load, considering a conservative fuel consumption rate. Verification that at least a one hour supply of fuel oil exists in a day tank provides assurance that a DG can operate continuously, and also allows the operating crew sufficient time to take corrective action should the automatic fuel oil transfer system not function properly.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Testing for water content every 31 days and removal of water from the fuel oil day tanks as necessary, eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water, as necessary, minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies meet the intent of Regulatory Guide 1.137 (Ref. 10). 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for manual fuel transfer systems are OPERABLE. Additional assurance of fuel oil transfer pump OPERABILITY is provided by meeting the testing requirements for pumps that are contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 13). Such testing is performed on a quarterly basis.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

The slow transfer of each 4.16 kV essential bus power supply from the preferred offsite circuit (i.e. - the startup transformer) to the alternate preferred offsite circuit (i.e. the standby transformer) demonstrates the OPERABILITY of the alternate preferred circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the Electrical Distribution Systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and the capability to reject the largest single load and return to the required voltage and frequency (i.e. - voltage ≥ 3744 V and ≤ 4576 V and frequency ≥ 59.5 Hz and ≤ 60.5 Hz) within predetermined periods of time (i.e., 1.3 seconds for voltage and 3.9 seconds for frequency) while maintaining an acceptable margin to the overspeed trip. The largest single load for each DG is a core spray pump motor (700 hp). This Surveillance may be accomplished by tripping its associated single largest post-accident load with the DG solely supplying the bus.

As specified by IEEE-308 (Ref. 14), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For both DGs, this represents 64.5 Hz, equivalent to 75% of the difference between nominal speed and the overspeed trip setpoint.

The time, voltage, and frequency tolerances specified in the Bases for this SR are derived from UFSAR Table 8.3-1 (Ref. 16) recommendations for response during load sequence intervals. The voltage and frequency are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are the steady state voltage and frequency to which the system must recover following load rejection within a predetermined time period. The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the Electrical Distribution Systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature and low lubricating oil pressure) are bypassed on either an ECCS initiation test signal or a LOOP 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 LOOPs 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, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

As specified by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the individual pump timers are reset.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), and takes into consideration plant conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

Under either LOCA conditions or during a loss of offsite power, loads are sequentially connected to the bus by a timed logic sequence using individual 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. Verifying the load sequence time interval is greater than or equal to 2 seconds ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load. The Allowable Values for the Core Spray and Low Pressure Coolant Injection Pump Start - Time Delay Relays, Table 3.3.5.1-1, Functions 1.e and 2.e, ensure this time interval is maintained as well as ensuring that safety analysis assumptions regarding ESF equipment time delays are not violated. Allowances for instrument inaccuracies in the load sequence time interval are also accounted for by the Pump Start - Time Delay Relay Allowable Value.

The Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

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 DG operation during a Loss of Offsite Power actuation test signal (LOOP signal) in conjunction with an ECCS initiation signal (LOCA signal). This test verifies all actions encountered from the LOOP/LOCA, including the LOOP/LOCA load shedding function and energization of the essential buses and respective loads from the DG. This Surveillance also demonstrates the as-designed operation of the standby power sources during a LOOP, including: 1) de-energization of the essential buses, 2) the dead bus load shedding function, and 3) that the DG receives a start signal. This surveillance also demonstrates that the DG automatically starts from the design basis actuation signal (LOCA signal). It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency (i.e., voltage ≥ 3744 V and ≤ 4576 V and frequency ≥ 59.5 Hz and ≤ 60.5 Hz) within the specified time (10 seconds). In lieu of multiple demonstrations of DG starting and achieving the required voltage and frequency in the specified time from each of the various start signals (LOOP, LOCA and LOOP/LOCA), and operation for ≥ 5 minutes, testing that adequately shows the capability of the DG to start from each of the signals is acceptable. The DG auto-start time of 10 seconds is derived from requirements of the accident analysis, (Ref. 15), for responding to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes (with a LOOP signal in conjunction with a LOCA signal present) in order to demonstrate that all of the starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or systems are not capable of being operated at full flow. In lieu of actual demonstration of 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 proper operation with each of the various signals present 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 of 24 months. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove the 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.

REFERENCES

1. UFSAR, Section 3.1.2.2.8.
2. UFSAR, Section 8.2 and Section 8.3.
3. UFSAR, Section 1.8.9.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93.

(continued)

BASES

REFERENCES (continued)

7. Generic Letter 84-15.

8. UFSAR, Section 3.1.2.2.9

9. Regulatory Guide 1.108.

10. Regulatory Guide 1.137.

11. [Deleted]

12. UFSAR, Section 6.3.

13. ASME Boiler and Pressure Vessel Code, Section XI.

14. IEEE Standard 308.

15. NEDC-32915P, "Duane Arnold Energy Center GE12 Fuel Upgrade Project", November 1999.

16. UFSAR, Table 8.3-1.

17. Regulatory Guide 1.9.

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 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 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 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 corresponding stresses result in the probabilities of occurrences 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 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 MODES 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 a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operation 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 MODES 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 for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (Diesel Generator (DG)) power.

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

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems – Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with Distribution System essential bus required OPERABLE by LCO 3.8.8, ensures that a diverse power source is available

(continued)

BASES

LCO (continued)

for providing electrical power support assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and reactor vessel draindown). Automatic initiation of the required DG during shutdown conditions is specified in LCO 3.3.5.1, ECCS Instrumentation, and LCO 3.3.8.1, LOP Instrumentation.

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective essential bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. The required offsite circuit consists of either: 1) the incoming autotransformer (T1) and disconnect (1401, 6782, 2812 or 4731), the incoming circuit breaker (8490) and disconnect (8491), the underground 34.5 kV line, the standby transformer (1X4), the 4160 volt supply line and one of the two supply circuit breakers (1A301 or 1A401) to essential buses 1A3 or 1A4, respectively, or 2) the incoming circuit breaker (5550 or 5560) and disconnect (5551 or 5555, respectively), the overhead 161 kV line, the startup transformer (1X3), one of the two 4160 volt supply lines and one of the two supply circuit breakers (1A302 or 1A402) to essential buses 1A3 or 1A4, respectively, if required by LCO 3.8.8.

The required DG must be capable of starting, accelerating to rated speed and voltage, connecting to its respective essential bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the essential buses. The necessary portions of Emergency Service Water are also required to provide appropriate cooling to each required DG.

Proper sequencing of loads, including non-essential load shedding capability, is a required function for DG OPERABILITY.

(continued)

BASES

LCO (continued)

In addition, proper timed logic sequence operation, is an integral part of offsite circuit OPERABILITY since its inoperability could impact the ability to start and maintain energized loads required OPERABLE by LCO 3.8.8. No automatic transfer capability is required for offsite circuits to be considered OPERABLE during shutdown conditions.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems providing 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. 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.

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. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

ACTIONS (continued)

A.1

An offsite circuit is considered inoperable if it is not available to supply power to either of the essential buses. If both essential 4.16 kV buses are required per LCO 3.8.8, one division 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 affected required feature(s) LCOs' ACTIONS.

Required features remaining powered from a qualified offsite power 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 required offsite circuit not available to either division, the option still exists to declare all affected 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 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 sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

(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)

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 would not be 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 essential bus, ACTIONS for LCO 3.8.8 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 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

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. SR 3.8.1.8 is not required to be met since only one offsite circuit is 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 a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude deenergizing a required 4160 V essential bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

The Diesel Generators (DGs) are provided with a storage tank having a fuel oil capacity sufficient to operate a DG for a period of 7 days while a DG is supplying maximum post Loss of Coolant Accident (LOCA) load demand discussed in UFSAR, Section 9.5.4 (Ref. 1). The maximum load demand is calculated using the assumption that only one DG is available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from storage tank to the day tanks by either of two transfer pumps. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe or valve, to result in the loss of more than one DG. The outside tanks, pumps, and piping are located underground.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity (or Saybolt Universal Viscosity), specific gravity (or API gravity), and total particulate contamination.

The DG Lubrication System is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The DG Lube Oil System is designed to provide automatic lube oil makeup to the DG crankcase for a minimum of 7 days of operation per UFSAR Section 8.3.1 (Ref. 7). This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has two independent air start systems each with adequate capacity for five successive normal start attempts per air receiver without recharging. A minimum of fifteen normal DG starts are provided for each DG per UFSAR Section

(continued)

BASES

BACKGROUND (continued)

8.3.1 (Ref. 7).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 6 (Ref. 4), and Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) Systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, 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 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient 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 Abnormal Operational Transient or a postulated DBA with loss of offsite power. DG day tank fuel oil requirements, as well as transfer capability from the storage tank to the day tanks, 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 normal DG start attempts without recharging the air start receivers.

(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 Abnormal Operational Transient or a postulated DBA. Because stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG for Conditions B, E, and F. 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) governed by separate Condition entry and application of associated Required Actions.

A.1

With the fuel oil level < 36,317 gallons in the 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 for 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

(continued)

ACTIONS

A.1 (continued)

be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil level in the lube oil makeup tank < 257 gallons, sufficient lube oil inventory to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil level 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 particulates 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 period prior to declaring both DGs inoperable. The 30 day Completion Time starts when initial analysis results are known and allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

(continued)

BASES

ACTIONS (continued)

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 mixture of new fuel oil and previously stored fuel oil remains acceptable, or to restore the stored fuel oil properties. If testing of the new fuel oil reveals fuel oil properties are not within limits, those properties not within limits must be tested, or restored to within limits. This restoration may involve feed and bleed procedures, filtering, or 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. Note that when the entire inventory of stored fuel oil is replaced with new fuel oil, the new fuel oil properties must be within specification prior to declaring the DGs OPERABLE.

E.1

With all starting air receivers associated with a DG with pressure < 150 psig, sufficient capacity for five successive DG start attempts may not exist. However, as long as any one receiver's pressure is ≥ 75 psig, there is adequate capacity for at least one start attempt (as shown during initial plant startup testing when successful DG starting was demonstrated with air receiver pressure as low as 50 psig), 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.

(continued)

BASES

ACTIONS (continued)

F.1

With a Required Action and associated Completion Time 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 tank to support a single DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 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 lubricating oil inventory is available to support at least 7 days of full load operation for each DG. The 257 gallon requirement for each DG is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from the lube oil makeup tank to the DG. The requirement is considered to be fulfilled by observing that the DG lube oil sump level is maintained in the normal band by the lube oil sump level controller.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

The tests listed below are a means of determining that the new and stored fuel oil has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tank without concern for contaminating the entire volume of fuel oil in the storage tank. These tests are to be conducted prior to adding the new fuel to the storage tank, but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D975-77 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D1298-85 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 28° and ≤ 38°;

c. Verify in accordance with ASTM D975-77, using ASTM Test Method D88-81, that viscosity at 100°F is ≥ 32.6 and ≤ 40.1 Saybolt Universal Seconds;

d. Verify that water and sediment are within limits when tested in accordance with ASTM D975-77 (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tank.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-77 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-77 (Ref. 6), except that a cloud point limit of 0°C has been selected due to fuel oil being stored underground and below the frost line, and that flash point and cetane number are not required. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

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 not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-89 (Ref. 6), Method A2 or A3. These methods involve a gravimetric determination of total particulate concentration in the fuel oil and have 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 test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of any refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles per air receiver without recharging. The pressure specified in this SR is intended to reflect a conservative value for which the five starts can be accomplished, assuming only one air start receiver is pressurized.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and the Air Start System for each DG.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. Checking for the presence of water every 31 days, and removing water, as necessary, eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with those recommended and established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the water is removed during performance of the Surveillance.

REFERENCES

1. UFSAR, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195, 1976.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. ASTM Standards: D975-77, D1298-85 and D2276-89.
7. UFSAR, Section 8.3.1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources – Operating

BASES

BACKGROUND

The 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 discussed in UFSAR Section 3.1.2.2.8 (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 intent of the recommendations of Safety Guide 6, as discussed in UFSAR Section 1.8.6. (Ref. 2) and IEEE-308 (Ref. 3).

The station service DC power sources provide both motive and control power to selected safety related equipment, as well as circuit breaker control power for some of the 4160 V, and all 480 V and lower, AC Distribution Systems. Each 125 VDC subsystem is energized by one 125 V station service battery and two 125 V battery chargers (one normally inservice charger and one swing charger that is able to separately charge either 125 VDC divisional battery). The 250 VDC subsystem can be energized by either of two 250 V battery chargers. Each battery is exclusively associated with a single 125 V or 250 VDC bus. The normal chargers are supplied from the same essential AC load groups for which the associated DC subsystem supplies the control power, while the swing 125 VDC charger can be supplied from either essential AC division and the two redundant 250 VDC chargers are supplied from separate essential AC divisions. The loads between the redundant 125 VDC subsystems are not transferable except for the 'B' actuation logic of the Automatic Depressurization System, which is normally powered from the Division 2 DC System, but which will automatically be powered from the Division 1 DC System if normal power is lost. The 125 VDC subsystems also provide control and instrumentation power for their respective DG.

(continued)

BASES

BACKGROUND (continued)

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system, acting as a voltage regulator. If a battery is disconnected from its distribution bus and only a charger is supplying bus voltage, the associated Distribution System shall be considered inoperable, as it cannot supply the peak power required for some event scenarios.

In case of loss of power to any battery charger, the DC loads are automatically powered from the battery until the redundant charger or swing charger is placed in service by operator action.

The DC Power Distribution System is described in more detail in Bases for LCO 3.8.7, "Distribution System – Operating," and LCO 3.8.8, "Distribution System – Shutdown."

Each battery (with a minimum of 57 cells for the 125 VDC batteries and 115 cells for the 250 VDC battery) has adequate storage capacity to carry the control and essential instrumentation power continuously for approximately 4 hours and the emergency motor loads for their required length of time.

Each DC battery 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 except for the swing 125 VDC battery charger which is mechanically interlocked to prevent being simultaneously connected to both distribution buses with double isolation circuit breakers.

The batteries for DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at the end of a nominal 20 year service cycle. The expected life of the batteries may exceed 20 years and will be adjusted based on engineering evaluations of each battery's capacity trend data as the batteries age. The minimum design voltage limits are 105V and 210V for the 125 VDC and 250 VDC subsystems, respectively.

(continued)

BASES

BACKGROUND (continued)

Each battery charger of DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each station service battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully charged state while supplying normal steady state loads (Ref. 10).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume that Engineered Safety Feature (ESF) Systems are OPERABLE. The DC Electrical Power System provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC 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 all onsite AC power; and

b. A worst case single failure.

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

LCO

The DC electrical power subsystems — with: 1) Division I and Division II 125 VDC subsystems, each consisting of one 125 V battery, the associated battery charger or the swing battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated bus, and 2) the 250 VDC subsystem consisting of one battery bank, one of the two battery chargers, and the corresponding control equipment and interconnecting cabling 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 Abnormal Operational Transient or a postulated DBA. Loss of any DC electrical power subsystem

(continued)

BASES

LCO (continued)

does not prevent the minimum safety function from being performed (Ref. 10).

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 Abnormal Operational 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 the Bases for LCO 3.8.5, "DC Sources – Shutdown."

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 8 hour limit is consistent with the allowed time for an inoperable DC Distribution System division.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. (In fact, loss of one Division of 125 VDC power is the most limiting single failure assumed in the accident analysis. The effect of a loss of a single Division of 125 VDC on the performance of the ECCS has been evaluated and found to be acceptable.) Since a subsequent worst case single failure could, however,

(continued)

BASES (continued)

ACTIONS

A.1 (continued)

result in the loss of minimum necessary DC electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 8 hours. The 8 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable 125 VDC electrical power subsystem and, if the 125 VDC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1 and B.2

If the station service 125 VDC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 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. The Completion Time to bring the unit to MODE 4 is consistent with the time suggested in Regulatory Guide 1.93 (Ref. 6).

C.1

With the 250 VDC electrical power subsystem inoperable, the HPCI System and associated PCIVs may be incapable of performing their intended function and must be immediately declared inoperable. The associated PCIVs referred to are: the RHR-SDC Isolation Valve (MO-1909), the RWCU Inlet Outboard Isolation Valve (MO-2701), the HPCI Steam Supply Isolation Valve (MO-2239),the HPCI Feedwater Injection Isolation Valve (MO-2312), and Main Steam Drain Line Isolation Valve (MO-4424).

D.1

Condition D corresponds to a level of degradation in the DC Electrical Power System that either causes a required safety function to be lost (e.g. when Division I and Division II of the 125 VDC electrical power subsystem are inoperable) or

(continued)

BASES

ACTIONS

D.1 (continued)

that results in a level of degradation that is severe enough to warrant an immediate shutdown (e.g. when one Division of the 125 VDC electrical power subsystem is inoperable concurrent with the 250 VDC electrical power subsystem being inoperable). When this situation exists, the plant may be 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 plant shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) 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 margin calculations (Ref. 4). The 7 day Frequency is consistent with manufacturer recommendations and with the intent of IEEE-450 (Ref. 7).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The connection resistance limits established for this SR must be no more than 20% above the resistance as measured during installation or not above the ceiling value established by the manufacturer. The resulting limits are 5.0 E-5 ohms for inter-cell connections and 1.4 E-4 ohms for inter-rack connections, inter-tier connections and terminal connections.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

The 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 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 12 month Frequency for this SR is consistent with the intent of IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 and SR 3.8.4.5 (continued)

The connection resistance limits for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer. The resulting limits are 5.0 E-5 ohms for inter-cell connections and 1.4 E-4 ohms for inter-rack connections, inter-tier connections and terminal connections.

The 12 month Frequency of these SRs is consistent with the intent of IEEE-450 (Ref. 7), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 3). According to the recommendations of Regulatory Guide 1.32 (Ref. 8), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes ensures that these requirements can be satisfied.

The Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency 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 on a required battery charger would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. This Note does not preclude performance of this SR on the "spare" battery charger (i.e., a charger not in-service or "required"). This Note also acknowledges that credit may be taken for unplanned events that satisfy the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 corresponds to the design duty cycle requirements as specified in Reference 4. The specific gravity and voltage of each cell shall be determined after the discharge. The Frequency of 24 months is consistent with the maximum length of an operating cycle.

This SR is modified by two Notes. Note 1 allows the performance of a performance discharge test in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 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 SR.

(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 test is described in the Bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; 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. 7) and IEEE-485 (Ref. 9). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 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 manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 7).

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.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 3.1.2.2.8.
2. UFSAR, Section 1.8.6.
3. IEEE Standard 308, 1971.
4. Calculations: CAL-E92-09, CAL-E92-08 and CAL-E92-07, latest approved revisions.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93.
7. IEEE Standard 450, 1980.
8. Regulatory Guide 1.32, February 1977.
9. IEEE Standard 485, 1983.
10. UFSAR, Section 8.3.2

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources – Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature Systems are OPERABLE. The 125 VDC Electrical Power System provides normal and emergency DC electrical power for the Diesel Generators (DGs), 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 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The DC electrical power subsystems – with: Division I and Division II 125 VDC subsystems each consisting of one 125 V battery, the associated battery charger or the swing battery charger and the corresponding control equipment and interconnecting cabling supply power to the associated distribution system; and, the 250 VDC subsystem consisting of the 250V battery, one of the two battery chargers and the corresponding control equipment and interconnecting cabling sufficient to provide electrical power to the outboard RHR-SDC suction isolation valve (MO-1909), are required to be OPERABLE to support required DC distribution subsystems required OPERABLE by LCO 3.8.8, "Distribution Systems – Shutdown." This requirement 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.

(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. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

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 3.8.8, 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 allowance of the option to declare required features inoperable with associated DC electrical power subsystems 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.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

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 performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC electrical power subsystems 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 UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (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 (DGs), 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 electrical power subsystems, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an Abnormal Operational Transient or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

(continued)

BASES (continued)

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, parameters for required battery cells are only required to be within limits when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met or 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. One cell is allowed to be out of service indefinitely because sufficient capacity is maintained by the remaining cells.

The pilot cell electrolyte level and float voltage are required to be verified to meet the 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. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met for required battery cells (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. If only one cell in a battery does not meet Category C limits, Required Action A.2 can be fulfilled if that cell is jumpered out within the Completion Time of 24 hours. Taking into consideration both the time required to perform the required verification and the assurance that the

BASES (continued)

ACTIONS

A.1, A.2, and A.3 (continued)

battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits.

Continued operation is only permitted for 31 days before parameters for required battery cells must be restored to within Category A and B limits. If only one cell in a battery does not meet Category A or B limits, Required Action A.3 can be fulfilled if that cell is jumpered out within the Completion Time of 31 days. 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 DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected (required) cell, sufficient capacity to supply the maximum expected load requirement is not ensured 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. One cell in each battery is allowed to be out of service indefinitely because sufficient capacity is maintained by the remaining cells.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1 (continued)

The SR should only be performed when the battery is on a float charge to allow obtaining meaningful, consistent, trendable readings. If the battery is on equalize charge or has been on equalize charge anytime during the previous 72 hours when the SR is due, performance of the SR should be delayed until the battery has been off equalize charge for 72 hours, utilizing the allowance of SR 3.0.2. If it is expected that a battery will need to be on equalize charge when the SR is due and past the extension time allowed by SR 3.0.2, the SR should be performed early before the battery is placed on equalize charge.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). In addition, within 24 hours of a battery discharge < 110 V for 125 V and < 220 V for 250 V or a battery overcharge > 150 V for 125 V and > 300 V for 250 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V for 125 V and ≤ 220 V for 250 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is within limits is consistent with a recommendation of IEEE-450 (Ref. 3) that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

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 manufacturer's recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperature 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 an equalizing charge, provided it is not overflowing. It is acknowledged that, following completion of an equalizing charge, electrolyte level may temporarily be above the specified limit, but not overflowing, for a short period of time. The recovery time for electrolyte level after the equalizing charge is considered part of the equalizing process. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 3), 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 ≥ 1.195 (0.015 below the manufacturer's 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. 3), the specific gravity readings are based on a temperature of 77°F (25°C).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

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 manufacturer's 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 specified for specific gravity for each connected cell is ≥ 1.190 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells 1.200 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C 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 voltage is based on IEEE-450 (Ref. 3), 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category C limit on average specific gravity ≥ 1.190, is based on manufacturer's recommendations (0.020 below the manufacturer's 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 less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

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) of Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current, while on float charge, is < 2 amps for station service batteries. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge of the designated pilot cell. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity 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. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC essential bus electrical power distribution subsystems.

The primary AC Distribution System consists of two 4.16 kV essential buses each having an offsite source of power as well as a dedicated onsite Diesel Generator (DG) source. Each essential bus is normally connected to the startup transformer (1X3). During a loss of the normal offsite power source to the essential buses, the alternate supply breaker from the standby transformer (1X4) attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the essential buses.

The secondary plant distribution system includes 480 VAC emergency buses 1B3 and 1B4 and associated load centers, and transformers.

There are two independent 125 VDC electrical power distribution subsystems and one independent 250 VDC electrical power distribution subsystem that support the necessary power for ESF functions.

The list of required distribution buses is presented in Table B 3.8.7-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume ESF Systems are OPERABLE. The AC and DC 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 Cooling (RCIC)System; and Section 3.6 Containment Systems.

(continued)

BASES

APPLICABILITY SAFETY ANALYSES (continued)

The OPERABILITY of the AC and DC Electrical Power Distribution 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 distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The AC and DC Electrical Power Distribution System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an Abnormal Operational Transient or a postulated DBA. The AC and DC electrical power distribution subsystems listed in the LCO are required to be OPERABLE. For the purposes of this LCO, the Intake Structure electrical power distribution subsystems (LCO 3.8.7.d) are not considered part of the Division I and Division II AC electrical power distribution subsystems (LCO 3.8.7.a), and the 125 VDC RCIC Motor Control Center (LCO 3.8.7.e) is not considered part of the Division I and Division II 125 VDC electrical power distribution subsystems (LCO 3.8.7.b).

Maintaining the Division 1 and 2 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF function is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC electrical power distribution subsystems require the associated buses and electrical circuits 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 battery and charger combination.

(continued)

BASES

LCO (continued)

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.7-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Other buses, such as motor control centers (MCC) and distribution panels which help comprise the AC and DC distribution systems may not be listed in Table B 3.8.7-1. 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 3.8.7-1 (e.g., a breaker supplying a single MCC 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 3.8.7-1 (e.g., loss of a 4.16 kV essential bus, which results in de-energization of all buses powered from the 4.16 kV essential 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 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 essential bus).

In addition, tie breakers between redundant safety related AC and DC 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 essential buses from being powered from the same offsite circuit.

(continued)

BASES (continued)

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 Abnormal Operational Transients; and

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

Electrical power distribution subsystem requirements for MODES 4 and 5 and other Conditions in which AC and DC electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.8, "Distribution Systems – Shutdown."

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels inoperable (except for the intake structure electrical power distribution subsystems, which are covered by Action D.1), and a loss of function has not yet occurred, the remaining AC 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 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 Condition, 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 on restoring

(continued)

BASES

ACTIONS

A.1 (continued)

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 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 combinations of either Division I and Division II AC or Division I and Division II DC (LCO 3.8.7.a or 3.8.7.b) required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, this LCO 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 the LCO, to restore the AC electrical power distribution system. At this time a DC bus could again become inoperable, and AC electrical power distribution system 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 this LCO 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 the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more essential Division I or Division II 125 VDC electrical power distribution subsystems inoperable, (except for 1D14, the motor control center serving the RCIC System, which is covered by Action F.1), and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. (In fact, loss of one Division of 125 VDC power is the most limiting single failure assumed in the accident analysis.) The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystems must be restored to OPERABLE status within 8 hours by powering the bus from the associated battery or charger.

Condition B represents one or more DC buses 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 divisions, and restoring power to the affected Division.

This 8 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 8 hours, 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;

(continued)

BASES

ACTIONS

B.1 (continued)

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;

c. The potential for an event in conjunction with a single failure of a redundant component;

d. The fact that this condition has specifically been analyzed as the most limiting single failure in the accident analysis, and found to be acceptable.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combinations of either Division I and Division II AC or Division I and Division II VDC (LCO 3.8.7.a or 3.8.7.b) required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently restored OPERABLE, the LCO 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 the LCO, to restore the DC distribution system. At this time, an AC bus could again become inoperable, and DC electrical power distribution system 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 the LCO was initially not met, instead of at the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable distribution 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 conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

With either one or both of the essential 480 VAC buses that serve the intake structure (1B9 or 1B20) inoperable, the River Water Supply (RWS) subsystem powered from the applicable bus is not capable of performing its intended function. Immediately declaring the associated RWS subsystem(s) inoperable allows the Actions of LCO 3.7.2, "RWS System and Ultimate Heat Sink", to apply appropriate limitations on continued reactor operation.

E.1

With a distribution panel or MCC in the 250 VDC electrical power distribution subsystem inoperable, the equipment powered from the inoperable distribution panel or MCC are not capable of performing their intended functions. Immediately declaring the associated supported features inoperable allows the Actions of the associated LCOs (LCO 3.5.1, "ECCS Operating", and LCO 3.6.1.3, "Primary Containment Isolation Valves") to apply appropriate limitations on continued reactor operation. For example, if distribution panel 1D40 is inoperable, MO-1909, MO-2701, MO-4424, MO-2312, and MO-2239 should be declared inoperable, and the HPCI System should be declared inoperable. If MCC 1D41 is inoperable, the HPCI System should be declared inoperable, and MO-2239 and MO-2312 should be declared inoperable. If MCC 1D42 is inoperable, MO-1909, MO-2701, and MO-4424 should be declared inoperable.

(continued)

BASES

ACTIONS (continued)

F.1

With the 125 VDC RCIC MCC inoperable, the equipment powered from the inoperable MCC are not capable of performing their intended functions. Immediately declaring the RCIC System and the outboard RCIC steam line isolation valve (MO-2401) inoperable allows the Actions of the associated LCOs (LCO 3.5.3, "RCIC System", and 3.6.1.3, "Primary Containment Isolation Valves") to apply appropriate limitations on continued reactor operation.

G.1

Condition G corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one AC or DC electrical power distribution subsystem is lost, and this results in the loss of a required function (except as allowed by Condition D), 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 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are 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 may be performed by verifying the absence of low voltage alarms, or by verifying a load powered from the bus is operating. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.7.2

This Surveillance verifies the "break-before-make" coordination of the circuit breakers for the LPCI Swing Bus (1B34A and 1B44A). This SR, when coupled with SR 3.5.1.7, demonstrates the ability of the LPCI Swing Bus to perform its intended safety function in support of the LPCI Loop Select design without compromising the independence of the AC Electrical Power Distribution System (Reference 3). Consequently, failure to satisfy this SR requires that both 1B34 and 1B44 buses be declared inoperable, and Condition G be entered until either 1B34 or 1B44 can be isolated from the Swing Bus, as a loss of all low pressure ECCS has potentially occurred. If the Swing Bus can be isolated from 1B34 or 1B44, then this SR is met, and the AC electrical power distribution subsystems are not inoperable. However, this will result in a failure to meet SR 3.5.1.7 (and Condition B of LCO 3.5.1 will be required to be entered since the LPCI system will be inoperable).

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. J. Hall (NRC) to L. Liu (IELP), "LPCI Swing Bus Design Modification (TAC No. 69556)," dated January 19, 1989

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a]
AC safety buses	4160 V	Essential Bus 1A3	Essential Bus 1A4
	480 V	Load Centers 1B3, 1B9	Load Centers 1B4, 1B20
	480 V	Motor Control Centers 1B32, 1B34	Motor Control Centers 1B42, 1B44
125 VDC buses	125 V	Distribution Panels 1D10, 1D11, 1D13 RCIC Motor Control Center 1D14	Distribution Panels 1D20, 1D21, 1D23
250 VDC buses	250 V	N/A	Distribution Panel 1D40 Motor Control Centers 1D41 and 1D42

[a] Each division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems - Shutdown

BASES

BACKGROUND	A description of the AC and DC Electrical Power Distribution System is provided in the Bases for LCO 3.8.7, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) Systems are OPERABLE. The AC and DC 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 and DC 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 and DC 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 and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(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 required 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 LCO, and implicitly required by the definition of OPERABILITY. In addition, it is acceptable for required buses to be cross-tied during shutdown conditions, permitting a single source to supply multiple redundant buses, provided the source is capable of maintaining proper frequency (if required) and voltage.

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 and DC 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

(continued)

BASES (continued)

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

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. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

<u>A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5</u>

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).

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

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.

Not withstanding 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the correct circuit breaker alignment. The correct circuit 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. 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. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.

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 serve as a backup to procedural core reactivity controls to prevent 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.

UFSAR Section 3.1.2.3.7 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.

One channel of instrumentation is provided to sense the position of the refueling platform, the loading of the refueling platform fuel grapple, and the full insertion of all control rods. Additionally, inputs are provided for the loading of the refueling platform frame mounted hoist, the loading of the refueling platform monorail mounted hoist and the full retraction of the fuel grapple. 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 and prevents 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 (RMCS) 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

(continued)

BASES

BACKGROUND (continued)

located over the reactor vessel. All refueling hoists have switches that 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 UFSAR analyses for the control rod removal error during refueling (Ref. 3) and the fuel assembly insertion error during refueling (Ref. 4). These analyses evaluate the consequences of control rod withdrawal 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.

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 of 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, considering maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To prevent criticality during refueling, the refueling interlocks associated with the Refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

(continued)

BASES

LCO (continued)

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel loaded, the refueling platform trolley frame mounted hoist fuel loaded, the refueling platform monorail mounted hoist fuel loaded, and the refueling platform fuel grapple fully retracted position inputs are required to be OPERABLE. These inputs are combined in logic circuits, which 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 required to be OPERABLE during in-vessel fuel movement only on the equipment which will be used to move fuel 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 CORE ALTERATIONS are not possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

A.1

With one or more of the required refueling equipment interlocks inoperable (does not include the one-rod-out interlock addressed in LCO 3.9.2), the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn).

(continued)

BASES

ACTIONS

A.1 (continued)

Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of at least one contact on the relay which inputs into the trip logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST. 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. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 7.6.2.
3. UFSAR, Section 15.4.3.
4. UFSAR, Section 15.4.4.

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.

UFSAR Section 3.1.2.3.7 requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

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

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

APPLICABLE SAFETY ANALYSES

The Refueling position one-rod-out interlock is explicitly assumed in the UFSAR analysis for 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 10 CFR 50.36(c)(2)(ii).

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. Since the DAEC design includes only one full-in indication (i.e., one reed switch for each control rod) that feeds both one-rod-out channels, another full-in indication may be used to temporarily provide input to both one-rod-out channels, using appropriate administrative controls. Under those conditions, this LCO is considered to be met, even though the full-in indication provided by design may not be functioning properly for a particular control rod. However, this normal full-in indication must be removed from providing input into the one-rod-out channels.

APPLICABILITY

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

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

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

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

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

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 switch 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 verifies acceptable response by verifying the change of state of at least one contact on the relay which inputs into the trip logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The 7 day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator to control rods not fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 7.6.2.2.
3. UFSAR, Section 15.4.3.

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").

UFSAR Section 3.1.2.3.7 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"), 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 for the control rod withdrawal error during refueling in the UFSAR (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3)

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	assumes all control rods are fully inserted. Thus, 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 10 CFR 50.36 (c)(2)(ii).
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 UFSAR. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1 (continued)

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. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 15.4.3.
3. UFSAR, Section 15.4.4.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication for each control rod provides necessary information 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 to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position 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 withdrawal of any other control rod. The all-rods-in interlocks provide the signals, one to each of the two Reactor Manual Control System rod block logic circuits.

UFSAR Section 3.1.2.3.7 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"), 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) assumes the functioning of the refueling interlocks and adequate SDM. The analysis for the fuel assembly insertion error (Ref. 3) assumes all control rods are fully inserted. The full-in position indication is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	withdrawn and that no more than one control rod can be withdrawn at a time. Control rod position indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Each control rod full-in position indication must be OPERABLE to provide the required input to the refueling interlocks. The position indication is OPERABLE if it provides correct position indication to the refueling interlock logic.
APPLICABILITY	During MODE 5, the control rods must have OPERABLE full-in position indications 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. 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 indications provide appropriate compensatory measures for separate inoperable position indications. As such, this Note has been provided, which allows separate Condition entry for each inoperable required control rod position indication.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2, A.1.3, A.2.1 and A.2.2

With one or more required full-in position indications 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 must be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicator(s) and electrically or hydraulically disarm the drive(s) to ensure that the control rod is not withdrawn. The control rods 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 indications provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are actuated 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 indications is performed to ensure that

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1 (continued)

when a control rod is withdrawn, the full-in position indication is not present. The full-in position indication 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 is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 15.4.3.
3. UFSAR, Section 15.4.4.

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.

UFSAR Section 3.1.2.3.7 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"), 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 analyses for the control rod withdrawal error during refueling (Ref. 2) and the fuel assembly insertion error (Ref. 3) evaluate the consequences of control rod withdrawal 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 10 CFR 50.36(c)(2)(ii).

(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 the Shutdown position 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 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 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

---

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

automatic insertion and the associated CRD scram accumulator pressure is ≥ 940 psig.

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 3.0.3 and SR 3.0.4.

REFERENCES

1. UFSAR, Section 3.1.2.3.7.
2. UFSAR, Section 15.4.3.
3. UFSAR, Section 15.4.4.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level in the reactor vessel cavity and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Ref. 1). Sufficient iodine activity would be retained to limit offsite doses from the accident to less than 10 CFR 100 limits.

APPLICABLE SAFETY ANALYSES

During movement of fuel assemblies or handling of control rods, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment. A minimum water level of 23 ft allows a decontamination factor of 100 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 water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory.

Analysis of the fuel handling accident inside containment is described in Reference 1. With a minimum water level of 23 ft 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. 2).

RPV water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

A minimum water level of 23 ft above the top of the 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. The minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV is conservative with respect to the corresponding water level of 36 ft in the Spent Fuel Pool (SFP) (Reference LCO 3.7.8, "Spent Fuel Storage Pool Water Level") for ensuring adequate fission product scrubbing and retention if a fuel assembly is dropped and damaged.

APPLICABILITY

LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) 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 3.7.8, "Spent Fuel Storage Pool Water Level."

ACTIONS

A.1

If the water level is < 23 ft above the top of the irradiated fuel assemblies seated within the RPV, all operations involving movement of 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft 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 operations is met. This verification can be performed using the normal RPV water level indication, which is referenced to Top of Active Fuel (TAF). 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. 1).

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. UFSAR, Section 15.7.1.
2. 10 CFR 100.11.

B 3.9 REFUELING OPERATIONS

B 3.9.7 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 described by UFSAR Section 3.1.2.4.5 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal after initial decay heat levels have decreased sufficiently. During the initial phases of cooldown, when decay heat levels are high, operation of both RHR System heat exchangers may be required (Ref. 2). Mode 5 is typically not entered until decay heat levels have fallen to levels that are within the capability of one RHR subsystem. In addition, procedures require the reactor coolant temperature to be maintained less than 150°F before the RPV may be disassembled and the RPV water level increased to the range when this Specification is applicable. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the 'B' recirculation loop and Reactor Pressure Vessel (RPV) bottom head. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchanger, to the reactor via the recirculation loop and associated low pressure coolant injection path, or to the reactor via Spent Fuel Pool and Spent Fuel Pool Cooling return flow path. The RHR heat exchangers transfer heat to the RHR Service Water (RHRSW) System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the RPV flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (Continued)

RHR shutdown cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level ≥ 21 ft-1 inch above the top of the RPV flange. A minimum water level of 21 ft-1 inch above the top of the RPV flange corresponds to a level of 36 ft in the Spent Fuel Pool (SFP). Therefore, SFP water level indication may be used to monitor RPV level when the RPV is flooded up and the SFP gates are removed. Other means of monitoring RPV water level are used when those conditions are not present. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability. In addition, when the reactor coolant temperature is ≥ 150 °F, one RHR shutdown cooling subsystem is required to be in operation to provide an active decay heat removal capability. At reactor coolant temperatures less than 150 °F, natural circulation alone is adequate to provide the required decay heat removal capability while maintaining adequate margin to the reactor coolant temperature (212 °F) at which a MODE change would occur. An OPERABLE RHR shutdown cooling subsystem consists of one RHR pump, a heat exchanger, an RHRSW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In addition, the necessary portions of the Emergency Service Water and River Water Supply System and Ultimate Heat Sink are required to provide appropriate cooling and a suction source to each required RHRSW pump.

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 when the reactor coolant temperature is ≥ 150 °F, nearly continuous operation is required. A Note is provided to allow a 2 hour exception to shut down the operating subsystem during any 8 hour period. This 8 hour period is a continuous rolling clock.

(continued)

BASES (continued)

LCO (continued)

The 2 hour exception provides operational flexibility for varying plant conditions.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level ≥ 21 ft-1 inch above the top of the RPV flange. In addition, one RHR shutdown cooling subsystem must be operating to provide decay heat removal when the reactor coolant temperature is ≥ 150 °F. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR Shutdown Cooling System requirements in MODE 5 with irradiated fuel in the reactor pressure vessel and with the water level < 21 ft-1 inch above the top of the RPV flange are given in LCO 3.9.8.

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be verified by administrative means 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 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.

Alternate decay heat removal methods are available to the operators for review and preplanning in operating procedures. Alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, feed and bleed to the torus via SRVs, Reactor Water Cleanup System, Reactor Cavity Floodup and Fuel Pool Cooling System

(continued)

BASES (continued)

ACTIONS

A.1 (continued)

return to the cavity. Heat losses to ambient surroundings may be included in the total capacity of the alternate heat removal methods employed to satisfy Required Action A.1. The alternate heat removal methods satisfy Required Action A.1 when the total alternate heat removal capacity exceeds the decay heat generation rate. 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 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 (i.e., one secondary containment isolation valve/damper and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. 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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If no RHR shutdown cooling is in operation when reactor coolant temperature is ≥ 150°F, except as permitted by the LCO Note, an alternate method of coolant circulation is required to be established within 1 hour. However, with the water level high, coolant circulation is assured by virtue of being flooded up to a level significantly higher than the minimum natural circulation level (i.e., lowest turnaround point for water in the steam separator) and thus, Required Action C.1 is met.

During the period of time when the reactor coolant is either being naturally circulated or circulated by another alternate method, the reactor coolant temperature must be periodically monitored to ensure proper circulation is maintained. The once per hour Completion Time is deemed appropriate due to the passive nature of the circulation process.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This Surveillance demonstrates that the RHR subsystem is in operation and circulating reactor coolant when reactor coolant temperature is ≥ 150°F.

The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability corresponding to the decay heat load that is present. 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. UFSAR, Section 3.1.2.4.5.
2. UFSAR, Section 5.4.7.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.8 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 described by UFSAR, Section 3.1.2.4.5 (Ref.1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal after initial decay heat levels have decreased sufficiently. During the initial phases of cooldown, when decay heat levels are high, operation of both RHR System heat exchangers may be required (Ref. 2). Mode 5 is typically not entered until decay heat levels have fallen to levels that are within the capability of one RHR subsystem. In addition, procedures require the reactor coolant temperature to be maintained less than 150 ^{o}F before the RPV may be disassembled. Both loops have a common suction from the 'B' recirculation loop and Reactor Pressure Vessel (RPV) bottom head. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the recirculation loop and associated low pressure coolant injection path or to the reactor via the Spent Fuel Pool and Spent Fuel Pool Cooling return flow path. The RHR heat exchangers transfer heat to the RHR Service Water (RHRSW) System. The RHR shutdown cooling mode is manually controlled.
APPLICABLE SAFETY ANALYSES	With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant. RHR shutdown cooling satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

In MODE 5 with irradiated fuel in the Reactor Pressure Vessel (RPV) and the water level < 21 ft-1 inch above the top of the RPV flange, two RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of one RHR pump, a heat exchanger, an RHRSW pump providing cooling to the heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. To meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. In addition, the necessary portions of the Emergency Service Water and River Water Supply Systems and the Ultimate Heat Sink are required to provide appropriate cooling and a suction source to each required RHRSW pump.

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 to shut down the operating subsystem during any 8 hour period. This 8 hour period is a continuously rolling clock. The 2 hour exception provides operational flexibility for varying plant conditions.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE, and one must be in operation in MODE 5, with irradiated fuel in the RPV and with the water level < 21 ft-1 inch above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS).

(continued)

BASES

APPLICABILITY (continued)

RHR Shutdown Cooling System requirements in MODE 5 with irradiated fuel in the RPV and with the water level ≥ 21 ft-1 inch above the top of the RPV flange are given in LCO 3.9.7, "Residual Heat Removal (RHR) – High Water Level."

ACTIONS

A.1

With one of the two required 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 verified by administrative means. With both required RHR shutdown cooling subsystems inoperable, another alternate method of decay heat removal must be verified by administrative means in addition to that verified 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 this alternate method(s) 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 operating procedures. Alternate methods that can be used include (but are not limited to) feed and bleed to radwaste or condenser, feed and bleed to the torus via SRVs, and Reactor Water Cleanup System. Heat losses to ambient surroundings may be included in the total capacity of the alternate heat removal methods employed to satisfy Required Action A.1. The alternate heat removal methods satisfy Required Action A.1 when the total alternate heat removal capacity exceeds the decay heat generation rate. The method used to remove decay heat should be the most prudent choice based on unit conditions.

(continued)

BASES

ACTIONS (continued)

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 (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. 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, the 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 subsystem is in operation, except as permitted by the LCO Note, an alternate method of coolant circulation (e.g., natural circulation when the minimum natural circulation level is maintained, starting a recirculation pump or RWCU in service) is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each subsequent loss of either forced or natural circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System), 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This Surveillance demonstrates that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability corresponding to the decay heat load that is present.

The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystems in the control room.

REFERENCES

1. UFSAR, Section 3.1.2.4.5.

2. UFSAR, Section 5.4.7.2.2.

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 > 212°F (normally corresponding to MODE 3).

Inservice 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 and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. In addition, a hydrostatic test pump or a control rod drive pump may be used to achieve required test pressure. 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 3.4.9, "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 at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing will eventually be required with minimum reactor coolant temperatures > 212°F.

At the DAEC, the hydrostatic testing required by Reference 1 is implemented using the allowances provided by Code Case N-498 (Ref. 2). This Code Case allows testing to be performed at the nominal operating pressure of 1025 psig. The system leakage testing is also performed at the nominal operating pressure as allowed by Reference 1.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 212°F, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.4.6, "RCS Specific Activity," limits 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 leak testing. The required pressure testing conditions 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 3. Therefore, these requirements will conservatively limit radiation releases to the environment.

Hydrostatic and leak testing, in and of themselves, are not considered to be Operations with the Potential for Draining the Reactor Vessel (OPDRVs). However, in the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure coolant injection and 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 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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	10 CFR 50.36(c)(2)(ii) 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 > 212°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 > 212°F, while some system leakage or hydrostatic testing may require the safety/relief valves to be gagged, preventing their OPERABILITY. 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 3.4.8, "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 > 212°F for the purpose 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 > 212°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.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to system leakage and hydrostatic testing operation. 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 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 an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements are 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 ≤ 212°F.

A.2.1 and A.2.2

Required Action A.2.1 and Required Action 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 Operation 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 ≤ 212°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 to reach MODE 4 from MODE 3.

(continued)

BASES (continued)

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, Edition and Addenda as Referenced in the Current Inservice Inspection Program.

2. Code Case N-498 (latest approved revision), Alternative Rules for 10 Year System Hydrostatic Testing for Class 1, 2 and 3 Systems, Section XI, Division 1.

3. UFSAR, Section 15.6.5.

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.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The acceptance criterion 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 normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (Run, Startup/Hot Standby, or Refuel) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no other 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 (Refs. 2 and 3). 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 10 CFR 50.36(c)(2)(ii) 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, "Inservice Leak 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

(continued)

BASES

LCO (continued)

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 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

(continued)

BASES

APPLICABILITY (continued)

Refuel (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.

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 operating 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 Action A.2, Required Action A.3.1, and Required Action 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.

(continued)

BASES (continued)

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. 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 verifies compliance with these Special Operations LCO requirements.

REFERENCES

1. UFSAR, Section 7.2.1.1.6.
2. UFSAR, Section 15.4.3.
3. UFSAR, Section 15.4.4.

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 the 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 UFSAR (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 10 CFR 50.36(c)(2)(ii) 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

(continued)

BASES

LCO (continued)

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 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 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," and LCO 3.9.5," Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item d.2 of this Special Operations LCO, minimize 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

(continued)

BASES

ACTIONS

A.1 (continued)

entered as directed by Required Action A.1. 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 Applicability by returning the reactor mode 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 are alternate 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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued)

It is preferred to electrically disarm the control rods since, in this case, drive water cools and minimizes crud accumulation in the drive. 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 withdrawal, the protection afforded by the LCOs involved, and hard-wired interlocks that preclude additional control rod withdrawals.

REFERENCES

1. UFSAR, Section 15.4.3.

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 UFSAR (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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing a 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 10 CFR 50.36(c)(2)(ii) 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

(continued)

BASES

LCO (continued)

function is not OPERABLE, or when 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 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," 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 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not

(continued)

BASES

ACTIONS (continued)

met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

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 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. Actions 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 be immediately 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 initiate action to 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. It is preferred to electrically disarm the control rods since, in this condition, drive water cools and minimizes crud accumulation in the drive. 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 hard-wired 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. UFSAR, Section 15.4.3.

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 is permitted to be withdrawn from a core cell containing one or more fuel assemblies. 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 UFSAR (Ref. 1) demonstrate that 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 to suspend all CORE ALTERATIONS 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 (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 10 CFR 50.36(c)(2)(ii) 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.

(continued)

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," 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 3.9.1, 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 to suspend all CORE ALTERATIONS 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 3.9.1, 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 reduce the potential for reactivity excursions.

(continued)

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 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 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 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. It is preferred to electrically disarm the control rods since, in this condition, drive water cools and minimizes crud accumulation in the drive. 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

(continued)

BASES (continued)

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)

ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied. 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 hard-wired interlocks to block an additional control rod withdrawal.

REFERENCES

1. UFSAR, Section 15.4.3.

(continued)

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 rod 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 bypassing the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the UFSAR (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 the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 10 CFR 50.36(c)(2)(ii) 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 either 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 fuel is loaded into the core with multiple control rods withdrawn, reload sequences are used to ensure that reactivity additions are minimized.

(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.2.1, 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 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.2.1, and Required Action A.2.2 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. UFSAR, Section 15.4.3.

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 include SDM demonstrations, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exemption 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 References 1 and 2. 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 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 References 1 and 2 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 10 CFR 50.36(c)(2)(ii) 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. Assurances 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 3.3.2.1.7 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 or other qualified member of the technical staff. 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 the LPSP of the RWM, 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), and LCO 3.3.2.1. With THERMAL POWER less than or equal to the LPSP of the RWM, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6.

(continued)

BASES

APPLICABILITY (continued)

While in MODES 3 and 4, control rod withdrawal is only allowed if performed in 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 and 2 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, provide mitigation of potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is 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 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 or other qualified member of the technical staff (i.e., a person trained in accordance with an approved training program for this test) 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 performed if SR 3.10.7.2 is satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 Surveillance demonstrates compliance with SR 3.3.2.1.7, thereby demonstrating that the RWM is OPERABLE. A Note has been added to indicate that this Surveillance does not need to be performed if SR 3.10.7.1 is satisfied.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).

2. Letter from T. Pickens (BWROG) to G.C. Lainas (NRC) "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.

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 the 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"). The limiting reactivity excursion event during control rod withdrawal 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 analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate 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 analyses (Refs. 1 and 2). In addition to the added requirements for the RWM, APRM, and control rod coupling, the notch out mode is specified for out of sequence withdrawals. Requiring the notch out 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 10 CFR 50.36(c)(2)(ii) 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 and 2.d) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, RPS MODE 2 requirements for Functions 2.a and 2.d of Table 3.3.1.1-1

(continued)

BASES

LCO (continued)

must be enforced and the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2), or must be verified by a second licensed operator or other qualified member of the technical staff. 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 individual 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 and A.2

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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

switch in the Shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling 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, "Control Rod Block Instrumentation," 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. The insertion of a manual scram prior to placing the reactor mode switch in the Shutdown or Refuel position is permitted by the definition of an Immediate Completion Time. This results in a condition that is consistent with the requirements for

(continued)

BASES

ACTIONS

B.1 (continued)

MODE 5 where the provisions of this Special Operations LCO are no longer required.

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 and 2.d, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. 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 or other qualified member of the technical staff. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.8.5 (continued)

being moved as well as operating experience related to uncoupling events.

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. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 970 psig is well below the expected pressure of 1100 psig. 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. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).

2. Letter from T. Pickens (BWROG) to G.C. Lainas, NRC, "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.