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Technical Specifications Bases - Revision 5

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2	August 28, 1998	October 30, 1998
3	October 28, 1998	October 30, 1998
4	March 16, 1999	October 18, 1999
5	October 18, 1999	October 18, 1999

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Special Test Exception (STE)-SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

The primary purpose of the SDM STE is to permit relaxation of existing LCOs to allow the performance of certain PHYSICS TESTS. These tests are constructed to determine the CEA worth.

Reference 1, Appendix B, Section XI requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that specified design conditions are not exceeded during normal operation and AOOs must be tested. Testing is required as an integral part of the design, fabrication, construction, and operation of the power plant. Requirements for notification of the Nuclear Regulatory Commission, for the purpose of conducting tests and experiments, are specified in Reference 1, 10 CFR 50.59.

The key objectives of a test program (Reference 2) are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in design and analysis;

c. Verify assumptions used for predicting plant response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that operating and emergency procedures are adequate.

To accomplish these objectives, testing is required prior to initial criticality, after each refueling shutdown, and during startup, low power operation, power ascension, and at power operation. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions, and that the core can be operated as designed (Reference 3, Section 13.4).

PHYSICS TESTS' procedures are written and approved in accordance with an established process. The procedures include all information necessary to permit a detailed execution of testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are independently reviewed prior to continued power escalation and long- term power operation. Examples of PHYSICS TESTS include determination of critical boron concentration, CEA group worths, reactivity coefficients, flux symmetry, and core power distribution.

APPLICABLE SAFETY ANALYSES

It is acceptable to suspend certain LCOs for PHYSICS TESTS because fuel damage criteria are not exceeded. Even if an accident occurs during PHYSICS TESTS with one or more LCOs suspended, fuel damage criteria are preserved because adequate limits on power distribution and shutdown capability are maintained during PHYSICS TESTS.

Reference 2 defines the requirements for initial testing of the facility, including PHYSICS TESTS. Requirements for reload fuel cycle PHYSICS TESTS are defined in the UFSAR Reference 3, Section 13.4. Although these PHYSICS TESTS are generally accomplished within the limits of all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. As long as the LHR remains within its limit, fuel design criteria are preserved.

In this test, the following LCOs are suspended:

a. LCO 3.1.1; and

b. LCO 3.1.6.

Therefore, this LCO places limits on the minimum amount of CEA worth required to be available for reactivity control when CEA worth measurements are performed.

The individual LCOs cited above govern SDM CEA group height, insertion, and alignment. Additionally, the LCOs governing RCS flow, reactor inlet temperature, and pressurizer pressure contribute to maintaining DNB parameter limits. The initial condition criteria for accidents sensitive to core power distribution are preserved by the LHR and DNB parameter limits. The criteria for the LOCA are specified in Reference 2, 10 CFR 50.46. The criteria for the loss of forced reactor coolant flow accident are specified in Reference 3, Chapter 14. Operation within the LHR limit preserves the LOCA criteria; operation within the DNB parameter limits preserves the loss of flow criteria.

Surveillance tests are conducted as necessary to ensure that LHR and DNB parameters remain within limits during PHYSICS TESTS. Performance of these SRs allows PHYSICS TESTS to be conducted without decreasing the margin of safety.

Requiring that shutdown reactivity equivalent to at least the highest estimated CEA worth (of those CEAs actually withdrawn) be available for trip insertion from the OPERABLE CEA provides a high degree of assurance that shutdown capability is maintained for the most challenging postulated accident, a stuck CEA. When LCO 3.1.1 is suspended, there is not the same degree of assurance during this test that the reactor would always be shut down if the highest worth CEA was stuck out and calculational uncertainties or the estimated highest CEA worth was not as expected (the single failure criterion is not met). This situation is judged acceptable, however, because SAFDLs are still met. The risk of experiencing a stuck CEA and subsequent criticality is reduced during this PHYSICS TESTS exception by the Surveillance Requirements; and by ensuring that shutdown reactivity is available, equivalent to the reactivity worth of the estimated highest worth withdrawn CEA (Reference 3, Chapter 3).

PHYSICS TESTS include measurement of core parameters or exercise of control components that affect process variables. Among the process variables involved are total planar radial peaking factor, total integrated radial peaking factor, T_q and ASI, which represent initial condition input (power peaking) to the accident analysis. Also involved are the shutdown and regulating CEAs, which affect power peaking and are required for shut down of the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

As described in LCO 3.0.7, compliance with STE LCOs is optional and, therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Test Exception 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

This LCO provides that a minimum amount of CEA worth is immediately available for reactivity control when CEA worth measurement tests are performed. The STE is required to permit the periodic verification of the actual versus predicted worth of the regulating and shutdown CEAs. The SDM requirements of LCO 3.1.1, the shutdown CEA insertion limits of LCO 3.1.5, and the regulating CEA insertion limits of LCO 3.1.6 may be suspended.

APPLICABILITY

This LCO is applicable in MODEs 2 and 3. Although CEA worth testing is conducted in MODE 2, sufficient negative reactivity is inserted during the performance of these tests to result in temporary entry into MODE 3. Because the intent is to immediately return to MODE 2 to continue CEA worth measurements, the STE allows limited operation to 6 consecutive hours in MODE 3, as indicated by the Note, without having to borate to meet the SDM requirements of LCO 3.1.1.

ACTIONS

A.1

With any CEA not fully inserted and less than the minimum required reactivity equivalent available for insertion, or with all CEAs inserted and the reactor subcritical by less than the reactivity equivalent of the highest worth CEA, restoration of the minimum SDM requirements must be accomplished by increasing the RCS boron concentration. The boration flow rate shall be ≥ 40 gpm and the boron concentration shall be ≥ 2300 ppm boric acid solution or equivalent. The required Completion Time of immediately is required to meet the assumptions of the safety analysis. It is assumed that boration will be continued until the SDM requirements are met.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification of the position of each partially or fully withdrawn full-length or part-length CEA is necessary to ensure that the minimum negative reactivity requirements for insertion on a trip are preserved. A 2-hour Frequency is sufficient for the operator to verify that each CEA position is within the acceptance criteria.

SR 3.1.7.2

Prior demonstration that each CEA to be withdrawn from the core during PHYSICS TESTS is capable of full insertion, when tripped from at least a 50% withdrawn position, ensures that the CEA will insert on a trip signal. The Frequency ensures that the CEAs are OPERABLE prior to reducing SDM to less than the limits of LCO 3.1.1.

REFERENCES

1. 10 CFR Part 50
2. Regulatory Guide 1.68, Revision 2, "Initial Test Programs for Water-Cooled Nuclear Power Plants," August 1978
3. UFSAR

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 AZIMUTHAL POWER TILT (T_q)

BASES

BACKGROUND

The purpose of this LCO is to limit the core power distribution to the initial values assumed in the accident analyses. Operation within the limits imposed by this LCO limits or prevents potential fuel cladding failures that could breach the primary fission product barrier and release fission products to the reactor coolant in the event of a LOCA, LOFA, ejected control element assembly (CEA) accident, or other postulated accident requiring termination by a Reactor Protective System trip function. This LCO limits the amount of damage to the fuel cladding during an accident by ensuring that the plant is operating within acceptable bounding conditions at the onset of a transient.

Methods of controlling the power distribution include:

a. Using CEAs to alter the axial power distribution;

b. Decreasing CEA insertion by boration, thereby improving the radial power distribution; and

c. Correcting off-optimum conditions (e.g., a CEA drop or misoperation of the unit) that cause margin degradations.

The core power distribution is controlled so that, in conjunction with other core operating parameters (e.g., CEA insertion and alignment limits), the power distribution does not result in violation of this LCO. The LSSS and this LCO are based on the accident analyses (Reference 1, Chapter 14), so that SAFDLs are not exceeded as a result of AOOs, and the limits of acceptable consequences are not exceeded for other postulated accidents.

Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in controlling the axial power distribution.

Power distribution is a product of multiple parameters, various combinations of which may produce acceptable power distributions. Operation within the design limits of power distribution is accomplished by generating operating limits for LHR and DNB.

The limits on LHR, F_{xy}^T, F_r^T. T_q, and ASI represent limits within which the LHR algorithms are valid. These limits are obtained directly from the core reload analysis.

Either of the two core power distribution monitoring systems, the Excore Detector Monitoring System or the Incore Detector Monitoring System, provides adequate monitoring of the core power distribution and is capable of verifying that the LCO limits are not exceeded. The Excore Detector Monitoring System performs this function by continuously monitoring ASI with OPERABLE quadrant symmetric excore neutron detectors and by verifying ASI is maintained within the limits specified in the COLR.

In conjunction with the use of the Excore Detector Monitoring System and in establishing the ASI limits, the following assumptions are made:

a. The CEA insertion limits of LCOs 3.1.5 and 3.1.6 are satisfied;

b. The T_q restrictions of LCO 3.2.4 are satisfied; and

c. F_{xy}^T does not exceed the limits of LCO 3.2.2.

The Incore Detector Monitoring System continuously provides a more direct measure of the peaking factors, and the alarms that have been established for the individual incore detector segments ensure that the peak LHRs are maintained within the limits specified in the COLR. The setpoints for these alarms include tolerances, set in conservative directions, for:

a. A measurement calculational uncertainty factor of 1.062;

b. An engineering uncertainty factor of 1.03;

c. An allowance of 1.002 for axial fuel densification and thermal expansion; and

d. A THERMAL POWER measurement uncertainty factor of 1.02 for THERMAL POWER > 50% RTP and 1.035 for THERMAL POWER > 20% RTP and ≤ 50% RTP.

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation or AOOs (Reference 1, Appendix 1C, Criterion 6). The power distribution and CEA insertion and alignment LCOs preclude core power distributions that violate the following fuel design criteria:

a. During a LOCA, peak cladding temperature must not exceed 2200°F (Reference 2);

b. During a LOFA, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected CEA accident, the energy input to the fuel must not exceed the accepted limits (Reference 1, Section 14.13); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Reference 1, Appendix 1C, Criterion 29).

The power density at any point in the core must be limited to maintain the fuel design criteria (Reference 2). This process is accomplished by maintaining the power distribution and reactor coolant conditions so that the peak LHR and DNB parameters are within operating limits supported by the accident analysis (Reference 1, Chapter 14), with due regard for the correlations between measured quantities, the power distribution, and uncertainties in determining the power distribution.

Fuel cladding failure during a LOCA is limited by restricting the maximum LHGR so that the peak cladding temperature does not exceed 2200°F (Reference 2). High peak cladding temperatures are assumed to cause severe cladding failure by oxidation due to a Zircaloy-water reaction.

The LCOs governing LHR, ASI, and the RCS ensure that these criteria are met as long as the core is operated within the ASI, F_{xy}^T, and F_r^T limits specified in the COLR, and within the T_q limits. The latter are process variables that characterize the three-dimensional power distribution of the reactor core. Operation within the limits for these

BASES

variables ensures that their actual values are within the range used in the accident analyses.

Fuel cladding damage does not normally occur while the reactor is operating at conditions outside these LCOs during otherwise normal operation. Fuel cladding damage could result, however, if an accident or AOO occurs from initial conditions outside the limits of these LCOs. Changes in the power distribution cause increased power peaking and correspondingly increased local LHRs.

The T_q satisfies 10 CFR 50.36(c)(2)(ii), Criterion 2.

LCO

The power distribution LCO limits are based on correlations between power peaking and the measured variables used as inputs to the LHR and DNB ratio operating limits. The power distribution LCO limits, except T_q, are provided in the COLR. The limits on LHR ensure that in the event of a LOCA, the peak temperature of the fuel cladding does not exceed 2200°F.

APPLICABILITY

In MODE 1 with THERMAL POWER > 50% RTP, T_q must be maintained within the limits assumed in the accident analysis to ensure that fuel damage does not result following an AOO. In other MODEs, this LCO does not apply because THERMAL POWER is not sufficient to require a limit on T_q.

ACTIONS

A.1 and A.2

If the measured T_q is > 0.03 and < 0.10, the calculation of T_q may be nonconservative. T_q must be restored within 4 hours, or F_{xy}^T and F_r^T must be determined to be within the limits of LCOs 3.2.2 and 3.2.3 within 4 hours, and determined to be within these limits every 8 hours thereafter, as long as T_q is out-of-limits. Four hours is sufficient time to allow the operator to reposition CEAs, and significant radial xenon redistribution cannot occur within this time. The 8 hour Completion Time ensures changes in F_{xy}^T and F_r^T can be identified before the limits of LCOs 3.2.2 and 3.2.3, respectively, are exceeded.

B.1

With $T_q > 0.10$, it must be restored to ≤ 0.10 with 2 hours. F_{xy}^T and F_r^T must be verified to be within their specified limits to ensure that acceptable flux peaking factors are maintained. Operation may proceed for a total of 2 hours, after the Condition is entered, while attempts are made to restore T_q to within its limit.

If the tilt is generated due to a CEA misalignment, operating at $\leq 50\%$ RTP allows for the recovery of the CEA. Except as a result of CEA misalignment, $T_q > 0.10$ is not expected; if it occurs, continued operation of the reactor may be necessary to discover the cause of the tilt. If this procedure is followed, operation is restricted to only those conditions required to identify the cause of the tilt. It is necessary to account explicitly for power asymmetries because the radial power peaking factors used in core power distribution calculations are based on an untilted power distribution.

If T_q is not restored to within its limits, the reactor continues to operate with an axial power distribution mismatch. Continued operation in this configuration may induce an axial xenon oscillation that causes increased LHRs when the xenon redistributes. If T_q cannot be restored to within its limits within 2 hours, reactor power must be reduced.

C.1

If Required Actions and associated Completion Times of Condition A or B are not met, THERMAL POWER must be reduced to $\leq 50\%$ RTP. This requirement provides conservative protection from increased peaking due to potential xenon redistribution and provides reasonable assurance that the core is operating within its thermal limits and places the core in a conservative condition. Four hours is a reasonable time to reach 50% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

T_q must be calculated at 12-hour intervals. T_q is determined using the incore and excore detectors. When one excore channel is inoperable and THERMAL POWER is > 75% RTP, the incore detectors shall be used. The 12-hour Frequency prevents significant xenon redistribution between surveillance tests.

REFERENCES

1. UFSAR
2. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants"

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protective System (RPS) Instrumentation-Operating

BASES

BACKGROUND

The RPS initiates a reactor trip to protect against violating the core specified acceptable fuel design limits and breaching the reactor coolant pressure boundary during anticipated operational occurrences (AOOs). By tripping the reactor, the RPS also assists the Engineered Safety Features (ESF) systems in mitigating accidents.

The protective systems have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as Limiting Conditions for Operation (LCOs) on other reactor system parameters and equipment performance.

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

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

- The departure from nucleate boiling ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling;
- Fuel centerline melting shall not occur; and
- The Reactor Coolant System (RCS) pressure SL of 2750 psia shall not be exceeded.

Maintaining the parameters within the above values ensures that the offsite dose will be within Reference 2, 10 CFR Parts 50 and 100, criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the plant life. The acceptable limit during accidents is that the offsite dose shall be maintained within the acceptance criteria given in the Reference 1, Chapter 14.

BASES

The RPS is segmented into four interconnected modules. These modules are:

- Measurement channels;
- Bistable trip units;
- RPS logic; and
- Reactor trip circuit breakers (RTCBs).

This LCO addresses measurement channels and bistable trip units. It also addresses the automatic bypass removal channel for those trips with operating bypasses. The RPS logic and RTCBs are addressed in LCO 3.3.3.

An instrument channel consists of the measurement channel and bistable trip unit for one channel of one Function.

The role of each of these modules in the RPS, including those associated with the logic and RTCBs, is discussed below.

Measurement Channels

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

The Power Range excore nuclear instrumentation drawers, Thermal Margin/Low Pressure (TM/LP) trip calculators, and Axial Power Distribution (APD) trip calculators, are considered components in the measurement channels. The power range nuclear instruments (NIs) provide average power and subchannel deviation signals. The wide range NIs provide a Rate of Change of Power-High trip. Two decades of overlap are provided between the power range NIs and the wide range NIs. Three RPS trip functions use a power level designated as Q power as an input. Q power is the higher of NI power and primary calorimetric power (ΔT power) based on RCS hot leg and cold leg temperatures. Trip functions using Q power as an input include the Power Level-High, TM/LP, and the APD trips.

BASES

The TM/LP and APD trip calculators provide the complex signal processing necessary to calculate the TM/LP trip setpoint, Asymmetric Steam Generator Transient (ASGT) trip setpoint, APD trip setpoint, Power Level-High trip setpoint, and Q power calculation.

The excore NI drawers (wide range and power range) and the TM/LP and APD trip calculators are mounted in the RPS cabinet, with one channel of each in each of the four RPS bays.

Four measurement channels with electrical and physical separation are provided for each parameter used in the direct generation of trip signals. These are designated Channels A through D. Measurement channels provide input to one or more RPS bistables within the same RPS channel. In addition, some measurement channels may also be used as inputs to Engineered Safety Features Actuation System (ESFAS) sensor modules, and most provide indication in the Control Room. Measurement channels used as an input to the RPS are never used for control functions.

When a measurement channel monitoring a parameter exceeds a predetermined setpoint, indicating an unsafe condition, the bistable in the bistable trip unit monitoring the parameter in that measurement channel will trip. Tripping two or more bistable trip units monitoring the same parameter de-energizes matrix logic, which in turn de-energizes the trip path logic. This causes all eight RTCBs to open, interrupting power to the control element assemblies (CEAs), allowing them to fall into the core.

Three of the four instrument channels are necessary to meet the redundancy and testability as described in Reference 1, Appendix 1C. The fourth channel provides additional flexibility by allowing one channel to be removed from service (trip bypass) for maintenance or testing, while still maintaining a minimum two-out-of-three logic. Thus, even with a channel inoperable, no single additional failure in the RPS can either cause an inadvertent trip or prevent a required trip from occurring.

Since no single failure will either cause or prevent a protective system actuation, and no protective channel feeds a control channel, this arrangement meets the requirements of Reference 1, Section 7.2.2 and Reference 3.

Many of the RPS Function trips are generated by comparing a single measurement to a fixed bistable setpoint. Certain Functions, however, make use of more than one measurement to provide a trip. The following trips use multiple measurement channel inputs:

- Steam Generator Level-Low Trip

  This trip uses the lower of the two steam generator levels as an input to a common bistable.

- Steam Generator Pressure-Low Trip

  This trip uses the lower of the two steam generator pressures as an input to a common bistable.

- Power Level-High Trip

  The Power Level-High trip uses Q power as its only input. Q power is the higher of NI power and ΔT power. Q power has a trip setpoint that tracks power levels downward so that the trip setpoint is always within a fixed increment above current power, subject to a minimum value.

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

- TM/LP and ASGT Trip

  Q power is only one of several inputs to the TM/LP trip. Other inputs include internal AXIAL SHAPE INDEX (ASI) and cold leg temperature based on the higher of two cold leg resistance temperature detectors. The TM/LP trip setpoint is a complex function of these inputs and represents a minimum acceptable RCS pressure to be compared to actual RCS pressure in the TM/LP trip unit.

Steam generator pressure is also an indirect input to the TM/LP trip via the ASGT. This Function provides a reactor trip when the secondary pressure in either steam generator exceeds that of the other generator by greater than a fixed amount. The trip is implemented by biasing the TM/LP trip setpoint upward so as to ensure TM/LP trip if an ASGT is detected.

- <u>APD-High Trip</u>

  Q power and subchannel deviation are inputs to the APD trip. The APD trip setpoint is a function of Q power, being more restrictive at higher power levels. It provides a reactor trip if actual ASI exceeds the APD trip setpoint.

<u>Bistable Trip Units</u>

Bistable trip units, mounted in the RPS cabinet, receive an analog input from the measurement channels, compare the analog input to trip setpoints, and provide contact output to the matrix logic. They also provide local trip indication and remote annunciation.

There are four channels of bistable trip units, designated A through D, for each RPS Function, one for each measurement channel. Bistable output relays de-energize when a trip occurs.

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

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

Trip Functions employing auxiliary trip units include the Loss of Load trip and the APD trip.

The APD trip, described above, is a complex function in which the actual trip comparison is performed within the APD calculator. Therefore the APD trip unit employs a contact input from the APD calculator.

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

The trip setpoints used in the bistable trip units are based on the analytical limits stated in Reference 1, Chapter 14, except for the APD and Loss of Load Functions, which are not credited in safety analyses. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account in the respective analytical limits. To allow for calibration tolerances, instrumentation uncertainties, instrument channel drift, and severe environment errors (for those RPS channels that must function in harsh environments, as defined by Reference 2, 10 CFR 50.49) RPS trip setpoints are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the trip setpoints, including their explicit uncertainties, is provided in Reference 4. The nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value. A channel is inoperable if its actual setpoint is not within its required Allowable Value.

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

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

RPS Logic

The RPS logic, addressed in LCO 3.3.3, consists of both matrix and trip path logic and employs a scheme that provides a reactor trip when bistables in any two of the four channels sense the same input parameter trip signal. This is called a two-out-of-four trip logic. This logic and the RTCB configuration are shown in Figure B 3.3.1-1.

Bistable relay contact outputs from the four bistable trip unit channels are configured into six logic matrices. Each logic matrix checks for a coincident trip in the same parameter in two bistable trip unit channels. The matrices are designated the AB, AC, AD, BC, BD, and CD matrices to reflect the bistable trip unit channels being monitored. Each logic matrix contains four normally energized matrix relays. When a coincidence is detected, consisting of a trip in the same Function in the two channels being monitored by the logic matrix, all four matrix relays de-energize.

The logic matrix relay contacts are arranged into trip paths, with one of the four matrix relays in each matrix opening contacts in one of the four trip paths. Each trip path provides power to one of the four normally energized RTCB control relays (K1, K2, K3, and K4). Thus, the trip paths each have six contacts in series, one from each matrix, performing a logical <u>OR</u> function by opening the RTCBs if any one or more of the six logic matrices indicate a coincidence condition.

Each trip path is responsible for opening one set of two of the eight RTCBs. When de-energized, the RTCB control relays (K-relays) interrupt power to the breaker undervoltage trip coils and simultaneously apply power to the shunt trip coils on each of the two breakers. Actuation of either the undervoltage or shunt trip coil is sufficient to open the RTCB and interrupt power from the motor generator (MG) sets to the control element drive mechanisms (CEDMs).

When a coincidence occurs in two RPS instrument channels from one Function, all four matrix relays in the affected matrix de-energize. This, in turn, de-energizes all four RTCB control relays, which simultaneously de-energize the undervoltage and energize the shunt trip coils in all eight RTCBs, tripping them open.

Matrix logic refers to the matrix power supplies, trip channel bypass contacts, and interconnecting matrix wiring between bistable and auxiliary trip units, up to but not including the matrix relays. Contacts in the bistable and auxiliary trip units are excluded from the matrix logic definition, since they are addressed separately.

The trip path logic consists of the trip path power source, matrix relays and their associated contacts, and all interconnecting wiring through the K-relay contacts in the RTCB control circuitry.

It is possible to change the two-out-of-four RPS logic to a two-out-of-three logic for a given input parameter, in one channel at a time, by trip bypassing select portions of the matrix logic. Trip bypassing a bistable trip unit effectively shorts the bistable relay contacts in the three matrices associated with that instrument channel. Thus, the bistables will function normally, producing normal trip indication and annunciation, but a reactor trip will not occur unless two additional instrument channels indicate a trip condition. Trip bypassing can be simultaneously performed on any number of parameters in any number of Functions, providing each parameter is bypassed in only one instrument channel per function at a time. Administrative controls prevent simultaneous trip bypassing of the same parameter in more than one instrument channel. Trip bypassing is normally employed during maintenance or testing.

In addition to the trip bypasses, there are also operating bypasses on select RPS trips. Some of these operating bypasses are enabled manually, others automatically, in all four RPS instrument channels for a Function when plant conditions do not warrant the specific trip function protection. All operating bypasses are automatically removed when enabling bypass conditions are no longer satisfied. Trip Functions with operating bypasses include

Rate of Change of Power-High, Reactor Coolant Flow-Low, Steam Generator Pressure-Low, APD-High, TM/LP, and Steam Generator Pressure Difference trips. The Loss-of-Load, Rate of Change of Power-High, and APD-High trips' operating bypasses are automatically enabled and disabled.

<u>RTCBs</u>

The reactor trip switchgear, addressed in LCO 3.3.3 and shown in Figure B 3.3.1-1, consists of eight RTCBs, which are operated in four sets of two breakers (four RTCB channels, including shunt trip coils and undervoltage coils). Power input to the reactor trip switchgear comes from two full capacity MG sets operated in parallel such that the loss of either MG set does not de-energize the CEDMs. There are two separate CEDM power supply buses, each bus powering half of the CEDMs. Power is supplied from the MG sets to each bus via two redundant trip paths. This ensures that a fault or the opening of a breaker in one trip path (i.e., for testing purposes) will not interrupt power to the CEDM buses.

Each of the four trip paths consists of two RTCBs in series. The two RTCBs within a trip path are actuated by separate trip paths.

The eight RTCBs are operated as four sets of two breakers (four RTCB channels, including shunt trip coils and undervoltage coils). Each set of two RTCBs is opened by the same K-relay. This arrangement ensures that power is interrupted to both CEDM buses, thus preventing trip of only half of the CEAs (a half trip). Any one inoperable RTCB in a RTCB channel (set of two breakers) will make the entire RTCB channel inoperable.

Each set of RTCBs is operated by either a manual trip push button or an RPS actuated K-relay. There are four manual trip push buttons, arranged in two sets of two, as shown in Figure B 3.3.1-1. Depressing both push buttons in either set will result in a reactor trip.

When a manual trip is initiated using the control room push buttons, the RPS trip paths and K-relays are bypassed, and the RTCB undervoltage and shunt trip coils are actuated independent of the RPS.

A manual trip channel includes the push button and interconnecting wiring to both RTCBs necessary to actuate both the undervoltage and shunt trip coils but excludes the K-relay contacts and their interconnecting wiring to the RTCBs, which are considered part of the trip path logic.

Functional testing of the RPS instrument and logic channels, from bistable input through the opening of individual sets of RTCBs, can be performed either at power or shutdown and is normally performed on a quarterly basis. Reference 1, Section 7.2 explains RPS testing in more detail.

APPLICABLE SAFETY ANALYSES

Most of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in Reference 1, Chapter 14 takes credit for most RPS trip Functions. Some Functions not specifically credited in the accident analysis are part of the Nuclear Regulatory Commission (NRC)-approved licensing basis for the plant. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. Other Functions, such as the Loss of Load trip, are purely equipment protective, and their use minimizes the potential for equipment damage.

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

1. <u>Power Level-High Trip</u>

   The Power Level-High trip provides reactor core protection against positive reactivity excursions that are too rapid for a Pressurizer Pressure-High or TM/LP trip to protect against. The following events require Power Level-High trip protection:

   - Uncontrolled CEA withdrawal event;
   - Excess load; and
   - CEA ejection event.

The first two events are AOOs, and fuel integrity is maintained. The third is an accident, and limited fuel damage may occur.

2. Rate of Change of Power-High Trip

The Rate of Change of Power-High trip is used to trip the reactor when excore logarithmic power, measured by the wide range logarithmic neutron flux monitors, indicates an excessive rate of change. The Rate of Change of Power-High trip Function minimizes transients for events such as a born dilution event, continuous CEA withdrawal, or CEA ejection from subcritical conditions. Because of this Function, such events are assured of having much less severe consequences than events initiated from critical conditions. The trip is automatically bypassed when NUCLEAR INSTRUMENT POWER is < 1E-4% RTP, when poor counting statistics may lead to erroneous indication. It is also bypassed at > 12% RTP, where other RPS trips provide protection from these events. With the RTCBs open, the Rate of Change of Power-High trip is not required to be OPERABLE; however, at least two wide range logarithmic neutron flux monitor channels are required by LCO 3.3.12 to be OPERABLE. Limiting Condition for Operation 3.3.12 ensures the wide range logarithmic neutron flux monitor channels are available to detect and alert the operator to a boron dilution event.

3. Reactor Coolant Flow-Low Trip

The Reactor Coolant Flow-Low trip provides protection during the following events:

- Loss of RCS flow;
- Loss of non-emergency AC power; and
- Reactor coolant pump (RCP) seized rotor.

The loss of RCS flow and of non-emergency AC power events are AOOs where fuel integrity is maintained. The RCP seized rotor is an accident where fuel damage may result.

4. Pressurizer Pressure-High Trip

The Pressurizer Pressure-High trip, in conjunction with pressurizer safety valves and main steam safety valves, provides protection against overpressure conditions in the RCS during the following events:

- Loss of Load; and
- Feedwater Line Break (FWLB).

5. Containment Pressure-High Trip

The Containment Pressure-High trip prevents exceeding the containment design pressure during certain loss of coolant accidents (LOCAs) or FWLB accidents. It ensures a reactor trip prior to, or concurrent with, a LOCA, thus assisting the ESFAS in the event of a LOCA or Main Steam Line Break (MSLB). Since these are accidents, SLs may be violated. However, the consequences of the accident will be acceptable.

6. Steam Generator Pressure-Low Trip

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators, which would result in a rapid uncontrolled cooldown of the RCS. This trip is needed to shut down the reactor and assist the ESFAS in the event of an MSLB. Since these are accidents, SLs may be violated. However, the consequences of the accident will be acceptable.

7. Steam Generator 1 and 2 Level-Low Trip

The Steam Generator 1 Level-Low and Steam Generator 2 Level-Low trips are required for the loss of normal feedwater and ASGT events.

The Steam Generator Level-Low trip ensures that low DNBR, high local power density, and the RCS pressure SLs are maintained during normal operation and AOOs, and, in conjunction with the ESFAS, the consequences of the Feedwater System pipe break accident will be acceptable.

8. APD-High Trip

The APD-High trip ensures that excessive axial peaking, such as that due to axial xenon oscillations, will not cause fuel damage. It ensures that neither a DNBR less than the SL, nor a peak linear heat rate that corresponds to the temperature for fuel centerline melting, will occur. This trip is the primary protection against fuel centerline melting.

9. Thermal Margin

a. TM/LP Trip

The TM/LP trip prevents exceeding the DNBR SL during AOOs and aids the ESFAS during certain accidents. The following events require TM/LP trip protection:

- RCS depressurization (inadvertent safety or power-operated relief valves opening);
- Steam generator tube rupture; and
- LOCA accident.

The first event is an AOOs, and fuel integrity is maintained. The second and third events are accidents, and limited fuel damage may occur, although only the LOCA is expected to result in fuel damage. The trip is initiated whenever the RCS pressure signal drops below a minimum value (P_{min}) or a computed value (P_{var}) as described below, whichever is higher. The setpoint is a Function of Q power, ASI, reactor inlet (cold leg) temperature, and the number of RCPs operating.

The minimum value of reactor coolant flow rate, the maximum AZIMUTHAL POWER TILT (T_q), and the maximum CEA deviation permitted for continuous operation are assumed in the generation of this trip signal. In addition, CEA group sequencing in accordance with LCO 3.1.7 is assumed. Finally, the maximum insertion of CEA banks that can occur during any AOO prior to a Power Level-High trip is assumed.

b. ASGT

The ASGT provides protection for those AOOs associated with secondary system malfunctions that result in asymmetric primary coolant temperatures. The most limiting event is closure of a single main steam isolation valve (MSIV). Asymmetric Steam Generator Transient is provided by comparing the secondary pressure in both steam generators in the TM/LP trip calculator. If the pressure in either exceeds that in the other by the trip setpoint, a TM/LP trip will result.

10. Loss of Load

The Loss of Load trip causes a trip when operating above 15% of RTP. This trip provides turbine protection, reduces the severity of the ensuing transient, and helps avoid the lifting of the main steam safety valves during the ensuing transient, thus extending the service life of these valves. No credit was taken in the accident analyses for operation of this trip. Its functional capability is required to enhance overall plant equipment service life and reliability.

Operating Bypasses

The operating bypasses are addressed in footnotes to Table 3.3.1-1. They are not otherwise addressed as specific table entries.

The automatic bypass removal features must function as a backup to manual actions for all trips credited in safety analyses to ensure the trip Functions are not operationally bypassed when the safety analysis assumes the Functions are not bypassed. The RPS operating bypasses are:

Zero power mode bypass (ZPMB) removal of the TM/LP, ASGT, and reactor coolant low flow trips when NUCLEAR INSTRUMENT POWER is < 1E-4% RTP. This bypass is manually enabled below the specified setpoint to permit low power testing. The wide range NI Level 1 bistable in the wide range drawer provides a signal to auxiliary logic, which then permits manual bypassing below the setpoint and removes the bypass above the setpoint.

Power rate of change bypass removal — The Rate of Change of Power-High trip is automatically bypassed at < 1E-4% RTP, as sensed by the wide range NI Level 1 bistable, and at > 12% RTP by the linear range NI Level 1 bistable, mounted in their respective NI drawers (Reference 5). Automatic bypass removal is also effected by these bistables when conditions are no longer satisfied.

Loss of Load and APD-High trip bypass removal — The Loss of Load and APD-High trips are automatically bypassed when at < 15% RTP as sensed by the linear range NI Level 1 bistable. The bypass is automatically removed by this bistable above the setpoint. This same bistable is used to bypass the Rate of Change of Power-High trip.

Steam Generator Pressure-Low trip bypass removal. The Steam Generator Pressure-Low trip is manually enabled below the pretrip setpoint. The permissive signal is removed, and the bypass automatically removed, when the Steam Generator Pressure-Low trip is above the pretrip setpoint.

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

LCO

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of any required portion of the instrument channel renders the affected channel(s) inoperable and reduces the reliability of the affected Functions. The specific criteria for determining channel OPERABILITY differ slightly between Functions. These criteria are discussed on a Function-by-Function basis below.

Actions allow trip channel bypass of individual instrument channels, but administrative controls prevent operation with a second channel in the same Function bypassed. Plants are restricted to 48 hours in a trip bypass condition before either restoring the Function to four channel operation (two-out-of-four logic) or placing the channel in trip (one-out-of-three logic).

Only the Allowable Values are specified for each RPS trip Function in the LCO. Nominal trip setpoints are established for the Functions via the plant-specific procedures. The nominal setpoints are selected to ensure the plant parameters do not exceed the Allowable Value if the bistable trip unit is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable, provided that operation and testing are consistent with the assumptions of the plant--specific setpoint calculations. Each nominal trip setpoint is more conservative than the analytical limit assumed in the safety analysis in order to account for instrument channel uncertainties appropriate to the trip Function. These uncertainties are defined in Reference 4. The nominal trip setpoint entered into a bistable is more conservative than that specified by the Allowable Value. A channel is inoperable if its actual setpoint is not within its required Allowable Value.

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

1. <u>Power Level-High Trip</u>

   This LCO requires all four instrument channels of the Power Level-High trip to be OPERABLE in MODEs 1 and 2.

   The Allowable Value is high enough to provide an operating envelope that prevents unnecessary Power Level-High trips during normal plant operations. The Allowable Value is low enough for the system to maintain a margin to unacceptable fuel cladding damage should a CEA ejection accident occur.

   The Power Level-High trip setpoint is operator adjustable and can be set at a fixed increment above the indicated THERMAL POWER level. Operator action is required to increase the trip setpoint as THERMAL POWER is increased. The trip setpoint is automatically decreased as THERMAL POWER decreases.

The trip setpoint has a maximum and a minimum setpoint.

Adding to this maximum value the possible variation in trip setpoint due to calibration and instrument errors, the maximum actual steady state THERMAL POWER level at which a trip would be actuated is 109% RTP, which is the value used in the safety analyses.

To account for these errors, the safety analysis minimum value is 40% RTP. The 10% step increase in trip setpoint is a maximum value assumed in the safety analysis. There is no uncertainty applied to the step in the safety analyses.

2. <u>Rate of Change of Power-High Trip</u>

This LCO requires four instrument channels of Rate of Change of Power-High trip to be OPERABLE in MODEs 1 and 2.

The high power rate of change trip serves as a backup to the administratively-enforced startup rate limit. The Function is not credited in the accident analyses; therefore, the Allowable Value for the trip is not derived from analytical limits.

3. <u>Reactor Coolant Flow-Low Trip</u>

This LCO requires four instrument channels of Reactor Coolant Flow-Low trip to be OPERABLE in MODEs 1 and 2.

The trip may be manually bypassed when NUCLEAR INSTRUMENT POWER falls below 1E-4% RTP. This operating bypass is part of the ZPMB circuitry, which also bypasses the TM/LP trip and provides a ΔT power block signal to the Q power select logic. The ZPMB allows low power physics testing at reduced RCS temperatures and pressures. It also allows heatup and cooldown with shutdown CEAs withdrawn.

This trip is set high enough to maintain fuel integrity during a loss of flow condition. The setting is low enough to allow for normal operating fluctuations from offsite power. To account for analysis uncertainty, the value in the safety analysis is 93% of design flow. Reactor Coolant System flow is maintained above design flow by LCO 3.4.1.

4. Pressurizer Pressure-High Trip

This LCO requires four instrument channels of Pressurizer Pressure-High trip to be OPERABLE in MODEs 1 and 2.

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

The Pressurizer Pressure-High trip concurrent with power-operated relief valve operation avoids unnecessary operation of the pressurizer safety valves (Reference 5).

5. Containment Pressure-High Trip

This LCO requires four instrument channels of Containment Pressure-High trip to be OPERABLE in MODEs 1 and 2.

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

6. Steam Generator Pressure-Low Trip

This LCO requires four instrument channels of Steam Generator Pressure-Low trip per steam generator to be OPERABLE in MODEs 1 and 2.

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

The analysis setpoint value includes harsh environment uncertainties, where appropriate.

The Function may be manually bypassed as steam generator pressure is reduced during controlled plant shutdowns. This operating bypass is permitted at a preset steam generator pressure. The bypass, in conjunction with the ZPMB, allows testing at low temperatures and pressures, and heatup and cooldown with the shutdown CEAs withdrawn. From a bypass condition, the trip will be automatically reinstated as steam generator pressure increases above the preset pressure.

7. Steam Generator Level-Low Trip

This LCO requires four instrument channels of Steam Generator Level - Low per steam generator to be OPERABLE in MODEs 1 and 2.

The Allowable Value is sufficiently below the normal operating level for the steam generators so as not to cause a reactor trip during normal plant operations. The trip setpoint is high enough to ensure a reactor trip signal is generated to prevent operation with the steam generator water level below the minimum volume required for adequate heat removal capacity, and ensures that the pressure of the RCS will not exceed its SL. The specified setpoint, in combination with the Auxiliary Feedwater Actuation System (AFAS), ensures that sufficient water inventory exists in both steam generators to remove decay heat following a Loss of Main Feedwater Flow event.

8. APD-High Trip

This LCO requires four instrument channels of APD-High trip to be OPERABLE in MODE 1, NUCLEAR INSTRUMENT POWER ≥ 15% RTP.

The Allowable Value curve was derived from an analysis of many axial power shapes with allowances for instrumentation inaccuracies and the uncertainty associated with the excore to incore ASI relationship.

The APD-High trip is automatically bypassed at < 15% RTP, as measured by the NIs, where it is not required for reactor protection (Reference 5).

9. Thermal Margin

a. TM/LP Trip

This LCO requires four instrument channels of TM/LP trip to be OPERABLE in MODEs 1 and 2.

The Allowable Value includes allowances for equipment response time, measurement uncertainties, processing error, and a further allowance to compensate for the time delay associated with providing effective termination of the occurrence that exhibits the most rapid decrease in margin to the SLs.

This trip may be manually bypassed when NUCLEAR INSTRUMENT POWER falls below 1E-4% RTP. This operating bypass is part of the ZPMB circuitry, which also bypasses the Reactor Coolant Flow-Low trip and provides a ΔT power block signal to the Q power select logic (Reference 5). The ZPMB allows low power physics testing at reduced RCS temperatures and pressures. It also allows heatup and cooldown with shutdown CEAs withdrawn.

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b. ASGT

This LCO requires four instrument channels of ASGT to be OPERABLE in MODEs 1 and 2.

The Allowable Value is high enough to avoid trips caused by normal operation and minor transients, but ensures DNBR protection in the event of DBAs. The difference between the Allowable Value and the analysis setpoint allows for instrument uncertainty.

The trip may be manually bypassed when NUCLEAR INSTRUMENT POWER falls below 1E-4% RTP as part of the ZPMB circuitry operating bypass. The Steam Generator Pressure Difference is subject to the ZPMB, since it is an input to the TM/LP trip and is not required for protection at low power levels (Reference 5).

10. Loss of Load

The LCO requires four Loss of Load instrument channels to be OPERABLE in MODE 1, NUCLEAR INSTRUMENT POWER ≥ 15% RTP.

The Loss of Load trip is automatically bypassed when NUCLEAR INSTRUMENT POWER falls below 15%, as measured by NIs, to allow loading the turbine.

Bypasses

The LCO on automatic bypass removal features requires that the automatic bypass removal feature of all four operating bypass channels be OPERABLE for each RPS Function with an operating bypass in the MODEs addressed in the specific LCO for each Function. All four automatic bypass removal features must be OPERABLE to ensure that none of the four RPS instrument channels are inadvertently bypassed.

The LCO applies to the automatic bypass removal feature only. If the bypass channel is failed so as to prevent entering a bypass condition, operation may continue.

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APPLICABILITY

This LCO is applicable in accordance with Table 3.3.3-1. Most RPS trip functions are required to be OPERABLE in MODEs 1 and 2 because the reactor is critical in these MODEs. The trips are designed to take the reactor subcritical, maintaining the SLs during AOOs and assisting the ESFAS in providing acceptable consequences during accidents. Exceptions are addressed in footnotes to the table. Exceptions to this APPLICABILITY are:

- The APD-High and Loss-of-Load trips are only applicable in MODE 1, NUCLEAR INSTRUMENT POWER ≥ 15% RTP because they are automatically bypassed at < 15% RTP, as measured by NIs, where they are no longer needed.
- The Rate of Change of Power-High trip, RPS logic, RTCBs, and manual trip are also required in MODEs 3, 4, and 5, with the RTCBs closed, to provide protection for boron dilution and CEA withdrawal events. The Rate of Change of Power-High trip in these lower MODEs is addressed in LCO 3.3.2. The RPS logic in MODEs 1, 2, 3, 4, and 5 is addressed in LCO 3.3.3.

Most trip functions are not required to be OPERABLE in MODEs 3, 4, and 5. In MODEs 3, 4, and 5, the emphasis is placed on return to power events. The reactor is protected in these MODEs by ensuring adequate SHUTDOWN MARGIN (SDM).

ACTIONS

The most common causes of instrument channel inoperability are outright failure or drift of the bistable trip unit or measurement channel sufficient to exceed the tolerance allowed by Reference 4. Typically, the drift is found to be small which, at worst, results in a delay of actuation rather than a total loss of Function. This determination is generally made during the performance of a CHANNEL CALIBRATION when the process instrument is set up for adjustment to bring it to within specification. Sensor Drift could also be identified during the CHANNEL CHECKS. CHANNEL FUNCTIONAL TESTs identify bistable trip unit drift. If the trip setpoint is less conservative than the Allowable Value in Table 3.3.1-1, the instrument channel is declared inoperable immediately, and the appropriate Condition(s) must be entered immediately.

In the event that either an instrument channel's trip setpoint is found nonconservative with respect to the Allowable Value or the transmitter, instrument loop, signal processing electronics, RPS bistable trip unit, or applicable automatic bypass removal feature when bypass is in effect, is found inoperable, then all affected Functions provided by that channel must be declared inoperable, and the plant must enter the Condition for the particular protection Function affected.

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

A Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function. The Completion Times of each inoperable Function will be tracked separately for each Function, starting from the time the Condition was entered.

<u>A.1, A.2.1, and A.2.2</u>

Condition A applies to the failure of a single instrument channel in any RPS automatic trip Function. Reactor Protective System coincidence logic is normally two-out-of-four.

If one RPS bistable trip unit or associated measurement channel is inoperable, startup or power operation is allowed to continue, providing the inoperable bistable trip unit is placed in bypass or trip within 1 hour (Required Action A.1).

The Completion Time of 1 hour allotted to restore, bypass, or trip the instrument channel is sufficient to allow the operator to take all appropriate actions for the failed channel, while ensuring that the risk involved in operating with the failed channel is acceptable.

The failed instrument channel is restored to OPERABLE status or is placed in trip within 48 hours (Required Action A.2.1 or Required Action A.2.2). Required Action A.2.1 restores the full capability of the Function.

Required Action A.2.2 places the Function in a one-out-of-three configuration. In this configuration, common cause failure of dependent channels cannot prevent a trip.

The Completion Time of 48 hours is based on operating experience, which has demonstrated that a random failure of a second instrument channel occurring during the 48-hour period is a low probability event.

B.1 and B.2

Condition B applies to the failure of two instrument channels in any RPS automatic trip Function.

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODEs, even though two instrument channels are inoperable, with one channel bypassed and one tripped. MODE changes in this configuration are allowed to permit maintenance and testing on one of the inoperable channels. In this configuration, the protective system is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE channels during the 48 hours permitted is remote.

Required Action B.1 provides for placing one inoperable channel in bypass and the other channel in trip within the Completion Time of 1 hour. This Completion Time is sufficient to allow the operator to take all appropriate actions for the failed channels, while ensuring that the risk involved in operating with the failed channels is acceptable. With one channel of protective instrumentation bypassed, the RPS Function is in a two-out-of-three logic; but with another channel failed, the RPS Function may be operating in a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the RPS Function in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, the reactor will trip.

One instrument channel should be restored to OPERABLE status within 48 hours for reasons similar to those stated under Condition A. After one channel is restored to OPERABLE status, the provisions of Condition A still apply to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action B.2 must be placed in trip if more than 48 hours have elapsed since the initial channel failure.

C.1 and C.2

The excore detectors are used to generate the internal ASI used as an input to the TM/LP and APD-High trips. Incore detectors provide a more accurate measurement of ASI. If one or more excore channels cannot be calibrated to match incore detectors, power is restricted or reduced during subsequent operations because of increased uncertainty associated with using uncalibrated excore channels.

The Completion Time of 24 hours is adequate to perform the Surveillance Requirement (SR) while minimizing the risk of operating in an unsafe condition.

D.1, D.2.1, D.2.2.1, and D.2.2.2

Condition D applies to one automatic bypass removal feature inoperable. If the automatic bypass removal feature for any operating bypass channel cannot be restored to OPERABLE status, the associated RPS channel may be considered OPERABLE only if the bypass is not in effect. Otherwise, the affected RPS channel must be declared inoperable, as in Condition A, and the bypass either removed or the automatic bypass removal feature repaired. The Bases for Required Actions and Completion Times are the same as discussed for Condition A.

E.1, E.2.1, and E.2.2

Condition E applies to two inoperable automatic bypass removal features. If the automatic bypass removal features cannot be restored to OPERABLE status, the associated RPS channel may be considered OPERABLE only if the bypasses are not in effect. Otherwise, the affected RPS channels must be declared inoperable, as in Condition B, and the bypasses either removed or the automatic bypass removal features repaired. Also, Required Action E.2.2 provides for the restoration of the one affected RPS channel to OPERABLE status within the rules of Completion Time specified under Condition B. Completion Times are consistent with Condition B.

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODEs, even though two automatic bypass removal features are inoperable, with one bistable trip unit bypassed and one tripped. MODE changes in this configuration are allowed to permit maintenance and testing on one of the inoperable automatic bypass removal features. In this configuration, the Function is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE automatic bypass removal features during the 48 hours permitted is remote.

F.1

Condition F is entered when the Required Action and associated Completion Time of Condition A, B, C, D, or E are not met for the APD-High trip and Loss-of-Load trip Functions.

If the Required Actions associated with these Conditions cannot be completed within the required Completion Times, the reactor must be brought to a MODE in which the Required Actions do not apply. The allowed Completion Time of 6 hours to reduce THERMAL POWER to < 15% RTP is reasonable, based on operating experience, to decrease power to < 15% RTP from full power conditions in an orderly manner and without challenging plant systems.

G.1

Condition G is entered when the Required Action and associated Completion Time of Condition A, B, C, D, or E are not met except for the APD-High trip and Loss-of-Load trip Functions.

If the Required Actions associated with these Conditions cannot be completed within the required Completion Times, the reactor must be brought to a MODE in which the Required Actions do not apply. The allowed Completion Time of 6 hours to be in MODE 3 is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one instrument channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument channel drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a qualitative assessment of the instrument channel combined with the instrument channel uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the transmitter or the signal processing equipment has drifted outside its limits. CHANNEL CHECKS are performed on the wide range logarithmic neutron flux monitor for the Rate of Change of Power-High trip Function.

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

SR 3.3.1.2

A daily calibration (heat balance) is performed when THERMAL POWER is ≥ 15%. The daily calibration shall consist of adjusting the "nuclear power calibrate" potentiometers to agree with the calorimetric calculation if the absolute difference is > 1.5%. The "ΔT power calibrate" potentiometers are then used to null the "nuclear power-ΔT power" indicators on the RPS Calibration and Indication Panel. Performance of the daily calibration ensures that the two inputs to the Q power measurement are indicating accurately with respect to the much more accurate secondary calorimetric calculation. The heat balance addresses overall gain of the instruments and does not include ASI.

The Frequency of 24 hours is based on plant operating experience and takes into account indications and alarms located in the Control Room to detect deviations in channel outputs. The Frequency is modified by a Note indicating this Surveillance must be performed until 12 hours after THERMAL POWER is ≥ 15% RTP. The secondary calorimetric is inaccurate at lower power levels. The 12 hours allows time for plant stabilization, data taking, and instrument calibration.

A second Note indicates the daily calibration may be suspended during PHYSICS TESTS. This ensures that calibration is proper both preceding and following physics testing at each plateau, recognizing that during testing, changes in power distribution and RCS temperature may render the calibration inaccurate.

SR 3.3.1.3

It is necessary to calibrate the excore power range channel upper and lower subchannel amplifiers such that the internal

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ASI used in the TM/LP trip and APD-High trip Functions reflects the true core power distribution as determined by the incore detectors. The SR is not required to be performed until 12 hours after THERMAL POWER is ≥ 20% RTP and required to be performed prior to operation above 90% RTP. Uncertainties in the excore and incore measurement process make it impractical to calibrate when THERMAL POWER is < 20% RTP. The Completion Time of 12 hours allows time for plant stabilization, data taking, and instrument calibration. The Frequency requires the SR be performed every 31 days after the initial performance prior to operation above 90% RTP. Requiring the SR prior to operations above 90% RTP is because of the increased uncertainties associated with using uncalibrated excore detectors. If the excore channels are not properly calibrated to agree with the incore detectors, power is restricted during subsequent operations because of increased uncertainty associated with using uncalibrated excore channels. The 31-day Frequency is adequate, based on operating experience of the excore linear amplifiers and the slow burnup of the detectors. The excore readings are a strong function of the power produced in the peripheral fuel bundles and do not represent an integrated reading across the core. Slow changes in neutron flux during the fuel cycle can also be detected at this Frequency.

SR 3.3.1.4

A CHANNEL FUNCTIONAL TEST is performed on each RPS instrument channel, except Loss of Load and Rate of Change of Power, every 92 days to ensure the entire channel will perform its intended function when needed.

In addition to reference voltage power supply tests, the RPS CHANNEL FUNCTIONAL TEST consists of three overlapping tests as described in Reference 1, Section 7.2. These tests verify that the RPS is capable of performing its intended function, from bistable input through the RTCBs. They include:

Bistable Tests

The bistable setpoint must be found to trip within the Allowable Values specified in the LCO and left set consistent with the assumptions of Reference 4. As-found values must also be recorded and reviewed for consistency with the assumptions of the frequency extension analysis. The requirements for this review are outlined in Reference 8.

A test signal is substituted as the input in one instrument channel at a time to verify that the bistable trip unit trips within the specified tolerance around the setpoint. This is done with the affected RPS channel bistable trip unit bypassed. Any setpoint adjustment shall be consistent with the assumptions of Reference 4.

Matrix Logic Tests

Matrix logic tests are addressed in LCO 3.3.3. This test is performed one matrix at a time. It verifies that a coincidence in the two instrument channels for each Function removes power from the matrix relays. During testing, power is applied to the matrix relay test coils and prevents the matrix relay contacts from assuming their de-energized state. This test will detect any short circuits around the bistable contacts in the coincidence logic, such as may be caused by faulty bistable relay or trip bypass contacts.

Trip Path Tests

Trip path logic tests are addressed in LCO 3.3.3. These tests are similar to the matrix logic tests, except that test power is withheld from one matrix relay at a time, allowing the trip path circuit to de-energize, opening the affected set of RTCBs. The RTCBs must then be closed prior to testing the other three trip path circuits, or a reactor trip may result.

The Frequency of 92 days is based on the reliability analysis presented in Reference 6.

SR 3.3.1.5

A CHANNEL CALIBRATION of the excore power range channels every 92 days ensures that the channels are reading accurately and within tolerance. The SR verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with the plant-specific SRs.

The as-found and as-left values must also be recorded and reviewed for consistency with the assumptions of the Frequency extension analysis. The requirements for this review are outlined in Reference 8.

A Note is added stating that the neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices with minimal drift and because of the difficulty of simulating a meaningful signal (Reference 7). Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration (SR 3.3.1.2) and the monthly linear subchannel gain check (SR 3.3.1.3). In addition, associated control room indications are continuously monitored by the operators.

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

<u>SR 3.3.1.6</u>

A CHANNEL FUNCTIONAL TEST on the Loss of Load, and Rate of Change of Power channels is performed prior to a reactor startup to ensure the entire channel will perform its intended function if required. The Loss of Load sensor cannot be tested during reactor operation without causing reactor trip. The Power Rate of Change-High trip Function is required during startup operation and is bypassed when shut down or > 12% RTP.

<u>SR 3.3.1.7</u>

Surveillance Requirement 3.3.1.7 is a CHANNEL FUNCTIONAL TEST similar to SR 3.3.1.4, except SR 3.3.1.7 is applicable only to Functions with automatic bypass removal features. Proper operation of operating bypasses are critical during plant startup because the bypasses must be in place to allow startup operation and must be removed at the appropriate points during power ascent to enable certain reactor trips. A 24-month SR Frequency is adequate to ensure proper automatic bypass removal feature operation as described in Reference 5. Once the operating bypasses are removed, the bypasses must not fail in such a way that the associated trip Function gets inadvertently bypassed. This feature is verified by the trip Function CHANNEL FUNCTIONAL TEST, SR 3.3.1.4. Therefore, further testing of the automatic bypass removal feature after startup is unnecessary.

SR 3.3.1.8

Surveillance Requirement 3.3.1.8 is the performance of a CHANNEL CALIBRATION every 24 months.

CHANNEL CALIBRATION is a check of the instrument channel, including the sensor. The SR verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument channel drift between successive calibrations to ensure that the channel remains operational between successive tests. CHANNEL CALIBRATIONS must be performed consistent with Reference 4.

The as-found and as-left values must also be recorded and reviewed for consistency with the assumptions of the frequency extension analysis. The requirements for this review are outlined in Reference 6.

The Frequency is based upon the assumption of a 24-month calibration interval for the determination of the magnitude of equipment drift.

The SR is modified by a Note to indicate that the neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices with minimal drift, and because of the difficulty of simulating a meaningful signal. Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration (SR 3.3.1.2) and the monthly linear subchannel gain check (SR 3.3.1.3).

SR 3.3.1.9

This SR ensures that the RPS RESPONSE TIMES are verified to be less than or equal to the maximum values assumed in the safety analysis. Individual component response times are

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not modeled in the analyses. The analyses model the overall or total elapsed time from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the RTCBs open. Response times are conducted on a 24-month STAGGERED TEST BASIS. Response time testing acceptance criteria are included in Reference 1, Section 7.2. This results in the interval between successive SRs of a given channel of n x 24 months, where n is the number of channels in the function. The Frequency of 24 months is based upon operating experience, which has shown that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences. Also, response times cannot be determined at power since equipment operation is required. Testing may be performed in one measurement or in overlapping segments, with verification that all components are tested.

A Note is added to indicate that the neutron detectors are excluded from RPS RESPONSE TIME testing because they are passive devices with minimum drift, and because of the difficulty of simulating a meaningful signal. Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration (SR 3.3.1.3).

REFERENCES

1. Updated Final Safety Analysis Report
2. Title 10 Code of Federal Regulations
3. Institute of Electrical and Electronic Engineers (IEEE) No. 279, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," August 1968
4. CCNPP Setpoint File
5. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 5, 1995, "Response to NRC Request for Review & Comment on Review of Preliminary Accident Precursor Analysis of Trip; Loss of 13.8 kV Bus; Short-Term Saltwater Cooling System Unavailability, CCNPP Unit 2"
6. Combustion Engineering Topical Report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" dated June 2, 1986, including Supplement 1, March 3, 1989

7. Letter from Mr. D. G. McDonald (NRC) to Mr. R. E. Denton (BGE), dated October 19, 1995, "Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit No. 1 (TAC No. M92479) and Unit No. 2 (TAC No. M92480)

8. Calvert Cliffs Procedure EN-4-104, "Surveillance Testing"

B 3.3 INSTRUMENTATION

B 3.3.4 Engineered Safety Features Actuation System (ESFAS) Instrumentation

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BACKGROUND

The ESFAS actuates necessary safety systems, based upon the values of selected unit parameters to mitigate accidents in order to protect the public and plant personnel from the accidental release of radioactive fission products.

The ESFAS contains devices and circuitry that generate the following signals when the monitored variables reach levels that are indicative of conditions requiring protective action:

1. Safety Injection Actuation Signal (SIAS);
2. Containment Spray Actuation Signal (CSAS);
3. Containment Isolation Signal (CIS);
4. Steam Generator Isolation Signal (SGIS);
5. Recirculation Actuation Signal (RAS) for the Containment Sump; and
6. AFAS Signal.

Equipment actuated by each of the above signals is identified in the Reference 1, Section 7.3.

Each of the above ESFAS actuation systems is segmented into four sensor channel and two actuation logic channels. Each sensor channel includes measurement channels and bistables (sensor modules). The actuation logic channels include two sets of logic circuitry (actuation logic modules) and actuation relay equipment. The actuation logic channels actuate ESFAS equipment trains that are sequentially loaded on the diesel generators (DGs).

Each of the four sensor modules monitors redundant and independent process measurement channels. Each sensor is monitored by at least one sensor module. The sensor module associated with each ESFAS sensor channel will trip when the monitored variable exceeds the trip setpoint. When tripped, the sensor channels provide outputs to the two actuation logic channels.

The two independent actuation logic channels compare the four sensor channel outputs. If a trip occurs in the same parameter in two or more sensor channels, the two-out-of-four logic in each actuation logic channel will initiate the associated train of ESFAS. Each train can provide protection to the public in the case of a DBA. Actuation logic is addressed in LCO 3.3.5.

Each of the four sensor channels is mounted in a separate cabinet, excluding the sensors and field wiring.

The role of the sensor channel (measurement channels and sensor modules) is discussed below; actuation logic channels are discussed in LCO 3.3.5.

Measurement Channels

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

Four measurement channels with electrical and physical separation are provided for each parameter used in the generation of actuation signals. These are designated Channels ZD through ZG. Measurement channels provide input to ESFAS sensor modules within the same ESFAS channel. In addition, some measurement channels may also be used as inputs to Reactor Protective System (RPS) bistable trip units, and most provide indication in the Control Room. Measurement channels used as an input to the RPS or ESFAS are not used for control functions.

When a measurement channel monitoring a parameter indicates an unsafe condition, the sensor module monitoring the parameter in that channel will trip. Tripping two or more channels of sensor modules monitoring the same parameter will de-energize both channels of actuation logic of the associated ESF equipment.

Three of the four sensor channels are necessary to meet the redundancy and testability requirements of Reference 1, Appendix 1C. The fourth channel provides additional flexibility by allowing one channel to be removed from service (maintenance bypass) for maintenance or testing while still maintaining a minimum two-out-of-three logic.

Since no single failure will either cause or prevent a protective system actuation and no protective channel feeds a control channel, this arrangement meets the requirements of proposed Reference 2.

Sensor Modules

Sensor modules receive an analog input (digital for RAS) from the measurement channels, compare the input to trip setpoints, and provide contact output to the actuation logic channels (Reference 3). They also provide local trip indication and remote annunciation.

There are four channels of sensor modules, designated ZD through ZG, for each ESF Function, one for each measurement channel.

The trip setpoints and Allowable Values used in the sensor modules are based on the analytical limits used in Reference 1, Chapter 14. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account in the respective analytical limits. To allow for calibration tolerances, instrumentation uncertainties, sensor channel drift, and severe environment errors, (for those ESFAS channels that must function in harsh environments, where appropriate, as defined by Reference 4. Engineered Safety Features Actuation System sensor modules trip setpoints are conservatively adjusted with respect to the analytical limits. A detailed description of the method used to calculate the trip setpoints, including their explicit uncertainties, is provided in Reference 5. The actual nominal trip setpoint entered into the sensor module is more conservative than that specified by the Allowable Value.. If the measured setpoint does not exceed the Allowable Value, the sensor module is considered OPERABLE.

Setpoints in accordance with the Allowable Value will ensure that the consequences of AOOs and DBAs will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed.

<u>ESFAS Logic</u>

It is possible to change the two-out-of-four ESFAS logic to a two-out-of-three logic for a given input parameter in one sensor channel at a time by disabling one sensor channel input to the logic. Thus, the sensor modules will function normally, producing normal trip indication and annunciation, but ESFAS actuation will not occur since the bypassed channel is effectively removed (blocked) from the coincidence logic. Sensor channel bypassing can be simultaneously performed on any number of parameters in any number of Functions, providing each parameter is bypassed in only one sensor channel per Function at a time. Sensor channel bypassing is normally employed during maintenance or testing.

Engineered Safety Features Actuation System logic is addressed in LCO 3.3.5.

APPLICABLE SAFETY ANALYSES

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

ESFAS protective Functions are as follows:

1. <u>SIAS</u>

   The SIAS ensures acceptable consequences during LOCA events, including steam generator tube rupture, and other DBAs. To provide the required protection, either a high containment pressure or a low pressurizer pressure signal will actuate SIAS. The SIAS actuates the Emergency Core Cooling System (ECCS), control room isolation, and performs other functions, such as starting the DGs.

2. CSAS

The CSAS actuates containment spray, preventing containment overpressurization during a LOCA or MSLB. Both a high containment pressure signal and a SIAS have to actuate to provide the required protection. This configuration reduces the likelihood of inadvertent containment spray.

3. CIS

The CIS actuates the Containment Isolation System, ensuring acceptable consequences during LOCAs and other DBAs (inside Containment). A high containment pressure signal will actuate CIS.

4. SGIS

The SGIS ensures acceptable consequences during an excessive loss of steam from the Main Steam System by isolating both steam generators if either generator indicates a low steam generator pressure. The SGIS, concurrent with or following a reactor trip, minimizes the rate of heat extraction and subsequent cooldown of the RCS during these events.

5. RAS

At the end of the injection phase of a LOCA, the refueling water tank (RWT) will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. Switchover from RWT to the containment sump must occur before the RWT empties to prevent damage to the ECCS pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support pump suction. Furthermore, early switchover must not occur so sufficient borated water is injected from the RWT to ensure the reactor remains shut down in the recirculation mode. An RWT

Level-Low trip signal, generated by a level switch, actuates the RAS.

6. AFAS Signal

An AFAS Signal actuates feedwater flow to both steam generators if a low level is indicated in either steam generator, unless the generator is ruptured.

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

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

A low steam generator water level signal will actuate auxiliary feed to both steam generators.

Secondary steam generator differential pressure (SG-1 > SG-2) or (SG-2 > SG-1) blocks auxiliary feedwater (AFW) to a generator identified as being ruptured. This input to the AFAS logic prevents loss of the intact generator while preventing feeding a ruptured generator during MSLBs and FWLBs. This prevents containment overpressurization and/or excessive RCS cooldown during these events.

The ESFAS satisfies 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

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

The Bases for the LCO on ESFAS Functions are:

1. SIAS

a. Containment Pressure-High Trip

This LCO requires four sensor channels of SIAS Containment Pressure-High trip to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value for this trip is set high enough to allow for small pressure increases in Containment expected during normal operation (i.e., plant heatup) and is not indicative of an offnormal condition. The setting is low enough to initiate the ESF Functions when a LOCA or other DBA condition is indicated. This allows the ESF systems to perform as expected in the accident analyses to mitigate the consequences of the analyzed accidents.

b. <u>Pressurizer Pressure-Low Trip</u>

This LCO requires four sensor channels of SIAS Pressurizer Pressure-Low trip to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value for this trip is set low enough to prevent actuating the SIAS during normal plant operation and pressurizer pressure transients. The setting is high enough that with a LOCA or some other DBA it will actuate to perform as expected, mitigating the consequences of the accidents.

The Pressurizer Pressure-Low trip may be blocked when pressurizer pressure is reduced during controlled plant shutdowns. This block is permitted below 1800 psia, and block permissive responses are annunciated in the Control Room. This allows for a controlled depressurization of the RCS, while maintaining administrative control of ESF protection. From a blocked condition, the block will be automatically removed as pressurizer pressure increases above 1800 psia, as sensed by two of the four sensor channels, in accordance with the block philosophy of removing blocks when the enabling conditions are no longer satisfied.

This LCO requires four channels of the automatic block removal features for SIAS Pressurizer Pressure-Low trip to be OPERABLE in MODEs 1, 2, and 3.

The block permissive channels consist of four sensor channels and two actuation sensor block modules. This LCO applies to failures in the four sensor channels, including measurement channels and sensor block modules. Failures in the actuation logic channels, including the manual bypass key switches, are considered actuation logic failures and are addressed in LCO 3.3.5.

This LCO applies to the automatic block removal feature, not the sensor block modules. If the block enable Function is failed so as to prevent entering a block condition, operation may continue.

The block permissive is set low enough so as not to be enabled during normal plant operation, but high enough to allow blocking prior to reaching the trip setpoint.

2. CSAS

The CSAS is initiated either manually or automatically. It is also necessary to have an automatic or manual SIAS for complete actuation. The CSAS opens the containment spray valves, where as SIAS actuates other related components. The SIAS requirement should always be satisfied on a legitimate CSAS, since the Containment Pressure-High trip signal field setpoint used in the SIAS is the same or below the setpoint used in the CSAS.

a. Containment Pressure-High Trip

This LCO requires four sensor channels of CSAS Containment Pressure-High trip to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value is set high enough to allow for small pressure increases in Containment expected during normal operation (i.e., plant heatup) and is not indicative of an offnormal condition. The setting is low enough to initiate the ESF Functions when an offnormal condition is indicated. This allows the ESF systems to perform as expected in the accident analyses to mitigate the consequences of the analyzed accidents.

The Containment Pressure-High trip setpoint is the same in the SIAS (Function 1), CIS (Function 3), and is a different setpoint for CSAS (Function 2). However, different logic is used in each of these Functions.

3. CIS

a. Containment Pressure-High Trip

This LCO requires four sensor channels of CIS Containment Pressure-High trip to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value is set high enough to allow for small pressure increases in Containment expected during normal operation (i.e., plant heatup) and is not indicative of an offnormal condition. The setting is low enough to initiate the ESF Functions when an offnormal condition is indicated. This allows the ESF systems to perform as expected in the accident analyses to mitigate the consequences of the analyzed accidents.

The Containment Pressure-High trip setpoint is the same in the SIAS (Function 1) and CIS (Function 3), and is a different setpoint for CSAS (Function 2). However, different logic is used in each of these Functions.

4. SGIS

The SGIS is required to be OPERABLE in MODEs 1, 2, and 3 except when all associated valves are closed and de-activated. De-activated means valve operating power is removed.

a. Steam Generator Pressure-Low Trip

This LCO requires four sensor channels of SGIS Steam Generator Pressure-Low trip for each steam generator to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value is set below the full load operating value for steam pressure so as not to interfere with normal plant operation. However, the setting is high enough to provide the required protection for excessive steam demand. An excessive steam demand causes the RCS to cool down, resulting in a positive reactivity addition to the core. An SGIS is required to prevent the excessive cooldown.

This Function may be manually blocked when steam generator pressure is reduced during controlled plant cooldowns. The block is permitted below 785 psia, and block permissive responses are annunciated in the Control Room. This allows a controlled depressurization of the secondary system, while maintaining administrative control of ESF protection. From a blocked condition, the block will be removed automatically as steam generator pressure increases above 785 psia, as sensed by two of the four sensor channels, in accordance with the block philosophy of removing blocks when the enabling conditions are no longer satisfied.

This LCO requires four channels per steam generator of the automatic block removal for SGIS Steam Generator Pressure-Low trip to be OPERABLE in MODEs 1, 2, and 3.

The automatic block removal features consist of four sensor channels and two actuation logic channels. This LCO applies to failures in the four sensor channels, including measurement channels and sensor block modules. Failures in the actuation logic channels, including the manual bypass key switches, are considered actuation logic failures and are addressed in LCO 3.3.5.

This LCO applies to the automatic block removal feature only. If the block enable Function is failed so as to prevent entering a block condition, operation may continue.

The block permissive is set low enough so as not to be enabled during normal plant operation, but high enough to allow blocking prior to reaching the trip setpoint.

5. <u>RAS for the Containment Sump</u>

   a. <u>RWT Level-Low Trip</u>

   This LCO requires four sensor channels of RWT Level-Low trip to be OPERABLE in MODEs 1, 2, and 3. The signal provided is a level indication from a level switch, not an analog signal.

   The upper limit on the Allowable Value for this trip is set low enough to ensure RAS does not actuate before sufficient water is transferred to the containment sump. Premature recirculation could impair the reactivity control Function of safety injection by limiting the amount of boron injection. Premature recirculation could also damage or disable the recirculation system if recirculation begins before the sump has enough water to prevent air entrainment in the suction. The lower limit on the RWT Level-Low trip Allowable Value is high enough to transfer suction to the containment sump prior to emptying the RWT.

6. <u>AFAS Signal</u>

   The AFAS logic actuates AFW to a steam generator on low level in that generator unless it has been identified as being ruptured.

   A low level in either generator, as sensed by a two-out-of-four coincidence of four wide range sensors for any generator, will generate an AFAS start signal,

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which starts both trains of AFW pumps, operates other equipment, and feeds both steam generators. The AFAS also monitors the secondary differential pressure in both steam generators and actuates an AFAS block signal to a ruptured generator, if the pressure in that generator is lower than that in the other generator by the differential pressure setpoint.

a. <u>Steam Generator 1/2 Level-Low Trip</u>

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

The Allowable Value ensures adequate time exists to initiate AFW, while the steam generators can function as a heat sink.

b. <u>Steam Generator Pressure Difference-High Trip (SG-1 > SG-2) or (SG-1 > SG-2)</u>

This LCO requires four sensor channels per steam generator of Steam Generator Pressure Difference-High trip to be OPERABLE in MODEs 1, 2, and 3.

The Allowable Value for this trip is high enough to allow for small pressure differences and normal instrumentation errors between the steam generator channels during normal operation without an actuation. The setting is low enough to detect and block feeding of a ruptured steam generator in the event of an MSLB or FWLB, while permitting the feeding of the intact steam generator.

APPLICABILITY

All ESFAS Functions are required to be OPERABLE in MODEs 1, 2, and 3. In MODEs 1, 2, and 3, there is sufficient energy in the primary and secondary systems to warrant automatic ESF system responses to:

- Close the MSIVs to preclude a positive reactivity addition;
- Actuate AFW to preclude the loss of the steam generators as a heat sink (in the event the normal feedwater system is not available);

- Actuate ESF systems to prevent or limit the release of fission product radioactivity to the environment by isolating Containment and limiting the containment pressure from exceeding the containment design pressure during a design basis LOCA or other DBAs; and
- Actuate ESF systems to ensure sufficient borated inventory to permit adequate core cooling and reactivity control during a design basis LOCA or other DBAs.

In MODEs 4, 5, and 6, automatic actuation of ESFAS Functions is not required because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating the ESF components, if required, as addressed by LCO 3.3.5. In LCO 3.3.5, manual capability is required for Functions other than AFAS in MODE 4, even though automatic actuation is not required. Because of the large number of components actuated on each ESFAS, actuation is simplified by the use of the manual actuation push buttons. Manual start of AFAS is not required in MODE 4 because AFW or shutdown cooling will already be in operation or available in this MODE.

The ESFAS actuation logic must be OPERABLE in the same MODEs as the automatic and manual actuation. In MODE 4, only the portion of the ESFAS logic responsible for the required manual actuation must be OPERABLE.

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

The most common cause of sensor channel inoperability is outright failure or drift of the sensor module or measurement channel sufficient to exceed the tolerance allowed by Reference 5.

Typically, the drift is small which, at worst, results in a delay of actuation rather than a total loss of Function. Determination of setpoint drift is generally made during the performance of a CHANNEL CALIBRATION when the process instrument is set up for adjustment to bring it to within specification. Sensor drift could also be identified during the CHANNEL CHECKS. CHANNEL FUNCTIONAL TESTS identify sensor module drift. If the actual trip setpoint is not within the Allowable Value in Table 3.3.4-1, the sensor channel is inoperable and the appropriate Condition(s) are entered.

In the event that either a sensor channel's trip setpoint is found nonconservative with respect to the Allowable Value in Table 3.3.4-1, or the sensor, instrument loop, signal processing electronics, ESFAS sensor module or applicable automatic block removal feature when block is in effect is found inoperable, all affected Functions provided by that sensor channel must be declared inoperable and the plant must enter the Condition statement for the particular protection Function affected.

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

A Note has been added to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function in Table 3.3.4-1. Completion Times for the inoperable channel of a Function will be tracked separately.

<u>A.1, A.2.1, and A.2.2</u>

Condition A applies to the failure of a single channel (measurement channel or sensor module) of one or more input parameters in the following ESFAS Functions:

1. <u>SIAS</u>

   Containment Pressure-High Trip
   Pressurizer Pressure-Low Trip

2. <u>CSAS</u>

   Containment Pressure-High Trip

3. <u>CIS</u>

   Containment Pressure-High Trip

4. <u>SGIS</u>

   Steam Generator Pressure-Low Trip

5. <u>RAS for the Containment Sump</u>

   RWT Level-Low Trip

6. <u>AFAS Signal</u>

   Steam Generator Level-Low Trip
   Steam Generator Pressure Difference-High Trip

Engineered Safety Features Actuation System coincidence logic is normally two-out-of-four. If one ESFAS sensor channel is inoperable, startup or power operation is allowed to continue as long as action is taken to restore the design level of redundancy.

If one ESFAS sensor channel is inoperable, startup or power operation is allowed to continue, providing the inoperable channel is placed in bypass or trip within 1 hour (Required Action A.1).

The Completion Time of 1 hour allotted to bypass or trip the sensor channel is sufficient to allow the operator to take all appropriate actions for the failed channel, and still ensures that the risk involved in operating with the failed channel is acceptable.

One failed sensor channel is restored to OPERABLE status or is placed in trip within 48 hours (Required Action A.2.1 or A.2.2). Required Action A.2.1 restores the full capability of the function. Required Action A.2.2 places the function in a one-out-of-three configuration. In this configuration, common cause failure of the dependent channel cannot prevent ESFAS actuation. The 48-hour Completion Time is based upon operating experience, which has demonstrated that a random failure of a second channel occurring during the 48-hour period is a low probability event.

B.1 and B.2

Condition B applies to the failure of two sensor channels in any of the following ESFAS functions:

1. SIAS

   Containment Pressure-High Trip
   Pressurizer Pressure-Low Trip

2. CSAS

   Containment Pressure-High Trip

3. CIS

   Containment Pressure-High Trip

4. SGIS

   Steam Generator Pressure-Low Trip

5. RAS for the Containment Sump

   RWT Level-Low Trip

6. AFAS Signal

   Steam Generator Level-Low Trip
   Steam Generator Pressure Difference-High Trip

With two inoperable sensor channels, one channel should be placed in bypass, and the other channel should be placed in trip within the 1-hour Completion Time. With one channel of protective instrumentation bypassed, the ESFAS Function is in two-out-of-three logic; but with another channel failed, the ESFAS may be operating with a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the ESFAS in a one-out-of-two logic. If any of the other OPERABLE channels receive a trip signal, ESFAS actuation will occur.

One of the failed sensor channels should be restored to OPERABLE status within 48 hours. After one channel is restored to OPERABLE status, the provisions of Condition A still apply to the remaining inoperable channel. Therefore, the channel that is still inoperable after completion of Required Action B.2 must be placed in trip if more than 48 hours has elapsed since the initial channel failure.

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODEs, even though two sensor channels are inoperable, with one channel bypassed and one tripped. MODE changes in this configuration are allowed, to permit maintenance and testing on one of the inoperable channels. In this configuration, the protective system is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE channels during the 48 hours permitted is remote.

C.1 and C.2

Condition C applies to the failure of one automatic block removal feature when the block is in effect.

The automatic block removal features are incorporated into the four sensor block modules (per steam generator for SGIS) and two block logic modules. Condition C applies to failures in the automatic block removal feature of one of the four sensor block modules. Failures in the block logic modules, including the block logic manual bypass key switches, are considered actuation logic failures and are addressed in LCO 3.3.5.

In Condition C, it is permissible to continue operation with the automatic block removal feature in one sensor block module failed, providing the sensor block module is disabled (Required Action C.1). This can be accomplished by adjusting the sensor block module setpoint, which disables the sensor block modules to both block logic modules. Therefore, a block permissive signal is not produced by the sensor block module.

Placing a sensor module in bypass defeats the block permissive input in one of the four channels to the two-out-of-four block removal logic, placing the automatic block removal feature in one-out-of-three logic. Thus, any of the remaining three channels is capable of removing the block feature when the block enable conditions are no longer valid.

In this configuration, common cause failure of the dependent channel cannot prevent block removal.

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

Condition D applies to two inoperable automatic block removal features. The automatic block removal features consist of four sensor block modules (per steam generator for SGIS) and two actuation logic channels. This Condition applies to failures in two of the four sensor block modules. With two of the four sensor block modules failed in a nonconservative direction (enabling the block feature), the automatic block removal feature is in two-out-of-two logic. Failures in the actuation logic channels, including the manual bypass key switches, are considered actuation logic failures and are addressed in LCO 3.3.5.

In Condition D, it is permissible to continue operation with two automatic block removal features failed, providing the sensor block modules are disabled in a similar manner as discussed for Condition C.

If the failed sensor block modules cannot be disabled, actions to address the inoperability of the affected sensor block modules must be taken. Required Action D.2.1 and Required Action D.2.2 are equivalent to the Required Actions for a two sensor channel failure (Condition B). Also similar to Condition B, after one inoperable sensor block module is restored, the provisions of Condition C still apply to the remaining inoperable automatic block removal feature, with the Completion Time measured from the point of the initial bypass channel failure. The 1-hour Completion Time minimizes the time that the plant is in two-out-of-two logic. The 48-hour Completion Time limits the time the plant is in one-out-of-two logic. Limits on the time in these logic conditions are similar to those found in Action B.

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODEs, even though two automatic block removal features are inoperable, with one sensor block module bypassed and one disabled. MODE changes in this configuration are allowed, to permit maintenance and testing on one of the inoperable automatic block removal features. In this configuration, the protective system is in a one-out-of-two logic, and the probability of a common cause failure affecting both of the OPERABLE automatic block removal features during the 48 hours permitted is remote.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition A, B, C, or D are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The SRs for any particular ESFAS Function are found in the SRs column of Table 3.3.4-1 for that Function. Most Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, CHANNEL CALIBRATION, and response time testing.

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one sensor channel to a similar parameter on other sensor channels. It is based on the assumption that sensor channels monitoring the same parameter should read approximately the same value. Significant deviations between sensor channels could be an indication of excessive sensor channel drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

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

SR 3.3.4.2

A CHANNEL FUNCTIONAL TEST is performed every 92 days to ensure the entire sensor channel will perform its intended function when needed.

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

A test signal is substituted for the input in one sensor channel at a time to verify that the bistable trips within the specified tolerance around the setpoint. Any setpoint adjustment shall be consistent with the assumptions of the Reference 5.

SR 3.3.4.3

Surveillance Requirement 3.3.4.3 is a CHANNEL FUNCTIONAL TEST similar to SR 3.3.4.2, except 3.3.4.3 is performed every 24 months and is only applicable to automatic block removal features of the sensor block modules. These include the Pressurizer Pressure-Low trip block and the SGIS Steam Generator Pressure-Low trip block.

The CHANNEL FUNCTIONAL TEST for proper operation of the automatic block removal features is critical during plant heatups because the blocks may be in place prior to entering MODE 3, but must be removed at the appropriate points during plant startup to enable the ESFAS Function. A 24-month SR Frequency is adequate to ensure proper automatic block removal module operation as described in Reference 3. Once the blocks are removed, the blocks must not fail in such a way that the associated ESFAS Function is inappropriately blocked. This feature is verified by the appropriate ESFAS Function CHANNEL FUNCTIONAL TEST.

The 24-month SR Frequency is adequate to ensure proper automatic block removal feature operation as described in Reference 3.

<u>SR 3.3.4.4</u>

CHANNEL CALIBRATION is a check of the sensor channel, including the automatic block removal feature of the sensor block module and the sensor. The SR verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for sensor channel drift between successive calibrations to ensure that the channel remains operational between successive surveillance tests. CHANNEL CALIBRATIONS must be performed consistent with Reference 5.

The as-found and as-left values must also be recorded and reviewed for consistency with the assumptions of the extension analysis. The requirements for this review are outlined in Reference 6.

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

BASES

SR 3.3.4.5

This SR ensures that the train actuation response times are the maximum values assumed in the safety analyses. Individual component response times are not modeled in the analyses. The analysis models the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment in both trains reaches the required functional state (e.g., pumps are rated discharge pressure, valves in full open or closed position). Response time testing acceptance criteria are included in Reference 1, Section 7.3. The test may be performed in one measurement or in overlapping segments, which verification that all components are measured.

Engineered Safety Feature Response Time tests are conducted on a STAGGERED TEST BASIS of once every 24 months. This results in the interval between successive tests of a given channel of n x 24 months, where n is the number of channels in the Function. Surveillance of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. Therefore, staggered testing results in Response Time verification of these devices every 24 months. The 24-month STAGGERED TEST BASIS Frequency is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. UFSAR
2. IEEE No. 279, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," August 1968
3. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 5, 1995, "Response to NRC Request for Review & Comment on Review of Preliminary Accident Precursor Analysis of Trip; Loss of 13.8 kV Bus; Short-Term Saltwater Cooling System Unavailability, CCNPP Unit 2"
4. 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"
5. CCNPP Setpoint File

BASES

6. Calvert Cliffs Procedure EN-4-104, "Surveillance Testing"

B 3.3 INSTRUMENTATION

B 3.3.10 Post-Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety Functions for DBAs (Reference 1).

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

The availability of PAM instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential indicator channels are identified by plant-specific documents (Reference 2) addressing the recommendations of Reference 3, as required by Reference 4.

Type A variables are included in this LCO because they provide the primary information required to permit the control room operator to take specific manually-controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions for some DBAs.

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

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the potential for causing a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public and for an estimate of the magnitude of any impending threat.

These key variables are identified by plant-specific analyses in Reference 2. These analyses identified the plant-specific Type A and Category I variables and provided justification for deviating from the NRC proposed list of Category I variables.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the OPERABILITY of Reference 3 Type A variables, so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures. These variables are restricted to preplanned actions for the primary success path of DBAs; and
- Take the specified, preplanned, manually-controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions.

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

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

Post-accident monitoring instrumentation that satisfies the definition of Type A in Reference 3 meets 10 CFR 50.36(c)(2)(ii), Criterion 3.

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

LCO

Limiting Condition for Operation 3.3.10 requires two OPERABLE indication channels for all but one Function to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following that accident.

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

An indication channel consists of field transmitters or process sensors and associated instrumentation, providing a measurable electronic signal based upon the physical characteristics of the parameter being measured, plus a display of the measured parameter.

The exceptions to the two-channel requirement are CIV position and the subcooled SMM. In the case of valve position, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration, either via indicated status of the active valve and prior knowledge of the passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Alternate means are available for obtaining information provided by the SMM.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.10-1.

1. <u>Wide Range Logarithmic Neutron Flux Monitors</u>

   Wide range logarithmic neutron flux is a Category I variable indication is provided to verify reactor shutdown.

The wide range logarithmic neutron flux PAM channels consist of two wide range neutron monitoring channels.

2, 3. RCS Outlet and Inlet Temperature

Reactor Coolant System outlet and inlet temperatures are Category I variables provided for verification of core cooling and long-term surveillance.

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

4. SMM

The RCS SMM is provided to monitor for inadequate core cooling by calculating the margin to saturation based on the RCS pressure/temperature relationships and displaying the calculated margin (1°F to 100°F) on a control room indicator. The SMM also generates a low subcooled margin alarm should the temperature margin drop below predetermined limits. The SMM is a microprocessor based instrument provided with inputs from the RCS hot and cold legs temperature instrumentation and wide range RCS pressure channels.

The RCS SMM is one of three components of inadequate core cooling instrumentation with the RCS SMM inoperable, the core exit thermocouple and reactor vessel water level monitoring systems provide diverse indication of core cooling.

5. Reactor Vessel Water Level Monitor

Reactor vessel water level monitors are provided for verification and long-term surveillance testing of core cooling.

The reactor vessel water level monitoring system uses a heated junction thermocouple system. The heated junction thermocouple system measures reactor coolant inventory with discrete heated junction thermocouple sensors located in different levels within a separator tube. The system provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory. The collapsed level is obtained over the same temperature and pressure range as the saturation measurements, thereby encompassing all operating and accident conditions where it must function. Also, it functions during the recovery interval. Therefore, it is designed to survive the high steam temperature that may occur during the preceding core recovery interval.

The level range extends from the top of the vessel down to 10" above the top of the fuel alignment plate. The response time is short enough to track the level during small break LOCA events. The resolution is sufficient to show the initial level drop, the key locations near the hot leg elevation, and the lowest levels just above the alignment plate. This provides the operator with adequate indication to track the progression of the accident and to detect the consequences of its mitigating actions or the functionality of automatic equipment.

A channel has eight sensors in a probe. A channel is OPERABLE if four sensors, one in the upper three and three in the lower five, are OPERABLE.

6. Containment Sump Water Level (wide range) Monitor

Containment sump water level monitors are provided for verification and long-term surveillance of RCS integrity.

Containment sump water level instrumentation consists of two level transmitters that provide input to control room indicators. The transmitters are located above the containment flood level and utilize sealed reference legs to sense water level.

7. <u>Containment Pressure (wide range) Monitor</u>

The containment pressure monitor is provided for verification of RCS and containment OPERABILITY.

Containment pressure instrumentation consists of three containment pressure transmitters with overlapping ranges that provide input to control room indicators. The transmitters are located outside the Containment and are not subject to a harsh environment.

8. <u>CIV Position Indicator</u>

Containment isolation valve position indicators are provided for verification of containment OPERABILITY and integrity.

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

The CIV position PAM instrumentation consists of ZL-505, 506, 515, 516, 2080, 2180, 2181, 3832, 3833, 4260, 5291, 5292, 6900, and 6901 (Reference 5).

9. Containment Area Radiation (high range) Detector

Containment area radiation detectors are provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operations in determining the need to invoke site emergency plans.

Containment area radiation instrumentation consists of two radiation detectors with displays and alarm in the Control Room. The radiation detectors have a measurement range of 1 to 10^8 R/hr.

10. Containment Hydrogen Monitors

Containment hydrogen monitors are provided to detect high hydrogen concentration conditions that represent a potential for Containment breach. This variable is also important in verifying the adequacy of mitigating actions.

Containment hydrogen instrumentation monitors samples from six locations inside the Containment. Two groups of three sampling lines from each Containment provide samples to the two cabinets in the sampling room. The cabinets contain the hydrogen analyzers and related equipment. The sampling system is fully operational from this remote station due to post-accident personnel safety considerations. Once the system is placed in the sampling mode, any malfunction or high hydrogen condition will generate a signal in the annunciator system in the main Control Room.

11. Pressurizer Pressure (wide range)

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

Wide range pressurizer pressure is measured by two pressure transmitters with a span of 0 psia to 4000 psia. The pressure transmitters are located inside the Containment. Redundant monitoring capability is provided by two indication channels. Control Room indications are provided.

Pressurizer pressure is a Type I variable because the operator uses this indication to monitor the cooldown of the RCS following a LOCA and other DBAs. Operator actions to maintain a controlled cooldown, such as adjusting steam generator pressure or level, would use this indication. Furthermore, pressurizer pressure is one factor that may be used in decisions to terminate RCP operation.

12. Steam Generator Pressure Transmitter

Steam generator pressure transmitters are Category 1 instruments and are provided to monitor operation of decay heat removal via the steam generators.

There are four redundant pressure transmitters per steam generator, but only two per steam generator are required to satisfy the Technical Specification Requirements. The transmitter provides wide range indication over the range from 0 to 1200 psia. Each transmitter provides input to control room indication. Since the primary indication used by the operator during an accident is the control room indicator, the PAM instrumentation Specification deals specifically with this portion of the instrument channel.

13. Pressurizer Level Transmitters

Pressurizer level transmitters are used to determine whether to terminate safety injection, if still in progress, or to reinitiate safety injection if it has been stopped. Knowledge of pressurizer water level is also used to verify the plant conditions necessary to establish natural circulation in the RCS and to verify that the plant is maintained in a safe shutdown condition.

Pressurizer Level instrumentation consists of two pressurizer level transmitters that provide input to control room indicators.

14. Steam Generator Water Level Transmitters

Steam Generator Water Level transmitters are provided to monitor operation of decay heat removal via the steam generators. The Category I indication of steam generator level is the extended startup range level instrumentation. The extended startup range level covers a span of -40 inches to -63 inches (relative to normal operating level), above the lower tubesheet. The measured differential pressure is displayed in inches of water at process conditions of the fluid. Redundant monitoring capability is provided by four transmitters. The uncompensated level signal is input to the plant computer and a control room indicator. Steam generator water level instrumentation consists of two level transmitters.

Operator action is based on the control room indication of steam generator water level. The RCS response during a design basis small break LOCA is dependent on the break size. For a certain range of break sizes, the boiler condenser mode of heat transfer is necessary to remove decay heat. Extended startup range level is a Type A variable because the operator must manually raise and control the steam generator level to establish boiler condenser heat transfer. Feedwater flow is increased until indication is in range.

15. Condensate Storage Tank Level Monitor

Condensate storage tank (CST) level monitors are provided to ensure water supply for AFW. The CST provides the ensured safety grade water supply for the AFW System. Inventory is monitored by a 0- to 144-inch level indication for each tank. Condensate storage tank level is displayed on a control room indicator and plant computer. In addition, a control room annunciator alarms on low level.

Condensate storage tank level is considered a Type A variable because the control room meter and annunciator are considered the primary indication used by the Operator. The DBAs that require AFW are the steam line break and loss of main feedwater. The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the hotwell.

16, 17, 18, 19. Core Exit Temperature Monitor

Core Exit Temperature monitors are provided for verification and long--term surveillance of core cooling.

An evaluation was made of the minimum number of valid core exit thermocouples necessary for inadequate core cooling detection. The evaluation determined the reduced complement of core exit thermocouples necessary to detect initial core uncovery and trend the ensuing core heatup. The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution and excore effects of condensate runback in the hot legs and nonuniform inlet temperatures. Based on these evaluations, adequate or inadequate core cooling detection is ensured with two valid core exit thermocouples per quadrant.

The design of the Incore Instrumentation System includes a Type K (chromel alumel) thermocouple within each of the 45 incore instrument detector assemblies.

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

The core exit thermocouples have a usable temperature range from 40°F to 2300°F, although accuracy is reduced at temperatures above 1800°F.

20. Pressurizer Pressure (low range)

Pressurizer low range pressure is a Category I variable provided for verification of core cooling and RCS integrity long-term surveillance.

Low-range pressurizer pressure is measured by two pressure transmitters with a span of 0 psia to 1600 psia. The pressure transmitters are located inside the Containment. Redundant monitoring capability is provided by two indication channels. Control Room indications are provided.

Pressurizer pressure is a Type I variable because the operator uses this indication to monitor the cooldown of the RCS following a LOCA and other DBAs. Operator actions to maintain a controlled cooldown, such as adjusting steam generator pressure or level, would use this indication. Furthermore, pressurizer pressure is one factor that may be used in decisions to terminate RCP operations.

Two indication channels are required to be OPERABLE for all but two Functions. Two OPERABLE channels ensure that no single failure, within either the PAM instrumentation or its auxiliary supporting features or power sources (concurrent with the failures that are a condition of or result from a specific accident), prevents the operators from being presented the information necessary for them to determine the safety status of the plant, and to bring the plant to and maintain it in a safe condition following that accident.

In Table 3.3.10-1 the exceptions to the two channel requirement are CIV position and the SMMs.

Two OPERABLE core exit thermocouples are required for each channel in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Therefore, two randomly selected thermocouples may not be sufficient to meet the two thermocouples per channel requirement in any quadrant. The two thermocouples in each channel must meet the additional requirement that one be located near the center of the core and the other near the core perimeter, such that the pair of core exit thermocouples indicate the radial temperature gradient across their core quadrant. The two channels in each core quadrant must be electronically independent. A core exit thermocouples operability is based on a comparison of the core exit thermocouple temperature indication with the hot leg resistance temperature detector temperature indication. Different criteria have been specified for interior core exit thermocouples and peripheral core exit thermocouples to account for the core radial power distribution. Plant specific evaluations in response to Item II.F.2 of NUREG-0737 should have identified the thermocouple pairings that satisfy these requirements. Two sets of two thermocouples in each quadrant ensure a single failure will not disable the ability to determine the radial temperature gradient.

For loop- and steam generator-related variables, the required information is individual loop temperature and individual steam generator level. In these cases, two channels are required to be OPERABLE for each loop of steam generator to redundantly provide the necessary information.

In the case of CIV position, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of the passive valve or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

The SMM monitors, core exit thermocouples, and the reactor vessel water level monitoring system comprise the inadequate core cooling instrumentation. The function of the inadequate core cooling instrumentation is to enhance the ability of the plant operator to diagnose the approach to, and recovery from, inadequate core cooling.

APPLICABILITY

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

ACTIONS

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

Note 2 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.10-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function, starting from the time the Condition was entered for that Function.

A.1

When one or more Functions have one required indication channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30-day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Reference 3 indication channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

This Required Action specifies initiation of actions in accordance with Specification 5.6.7, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative Required Actions. This Required Action is appropriate in lieu of a shutdown requirement, given the likelihood of plant conditions that would require information provided by this instrumentation. Also, alternative Required Actions such as grab sampling or diverse indications are identified before a loss of functional capability condition occurs.

C.1

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

D.1

When two required hydrogen monitor channels are inoperable, Required Action D.1 requires one channel to be restored to OPERABLE status. This Required Action restores the monitoring capability of the hydrogen monitor. The 72-hour Completion Time is based on the relatively low probability of an event requiring hydrogen monitoring and the availability of alternative means to obtain the required information. Continuous operation with two required channels inoperable is not acceptable because alternate indications are not available.

E.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.10-1. The applicable Condition referenced in the Table is Function-dependent. Each time Required Action C.1 or D.1 is not met and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Condition C are not met, and Table 3.3.10-1 directs entry into Condition F, the plant must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours.

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

G.1

Alternate means of monitoring containment area radiation have been developed and tested. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The reactor vessel water level monitoring system is one of three components of the inadequate core cooling instrumentation. The SMMs and core exit thermocouples could be used to monitor inadequate core cooling. If these alternate means are used, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.7. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note at the beginning of the SRs specifies that the following SRs apply to each PAM instrumentation Function in Table 3.3.10-1.

SR 3.3.10.1

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

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

For the Hydrogen Monitors, a CHANNEL CHECK is performed by drawing a sample from the Waste Gas System through the monitor.

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

SR 3.3.10.2

A CHANNEL CALIBRATION is performed every 46 days on a staggered test basis for the Containment Hydrogen Analyzers. The CHANNEL CALIBRATION is performed using sample gases in accordance with manufacturer's recommendations.

SR 3.3.10.3

A CHANNEL CALIBRATION is performed every 24 months or approximately every refueling. CHANNEL CALIBRATION is a check of the indication channel including the sensor. The SR verifies the channel responds to the measured parameter within the necessary range and accuracy. A Note allows exclusion of neutron detectors, Core Exit Thermocouples, and Reactor Vessel Level Monitor System from the CHANNEL CALIBRATION.

The Frequency is based upon operating experience and consistency with the typical industry refueling cycle and is justified by an 24 month calibration interval for the determination of the magnitude of equipment drift.

REFERENCES

1. Letter from Mr. R. E. Denton (BGE) to NRC Document Control Desk, dated June 6, 1995, "License Amendment Request; Extension of Instrument Surveillance Intervals"
2. Letter from Mr. J. A. Tiernan (BGE) to NRC Document Control Desk, dated August 9, 1988, "Regulatory Guide 1.97 Review Update"
3. Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident (Errata Published July 1981), December 1975
4. NUREG-0737, Supplement 1, Requirements for Emergency Response Capabilities (Generic Letter 82-33), December 17, 1982
5. UFSAR, Chapter 7, "Instrumentation and Control"

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core makeup the RCS. Component joints are made by welding, bolting, rolling, or pressure loading. Valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

Reference 1, Appendix 1C, Criterion 16 requires means for detecting reactor coolant LEAKAGE. Reference 2 describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the facility and the public.

A limited amount of leakage inside Containment Structure is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analysis radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a LOCA.

BASES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for a LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 1 gpm primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside the Containment Structure resulting from a steam line break accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a SGTR. The leakage contaminates the secondary fluid.

Reference 1, Section 14.15 analysis for SGTR assumes the contaminated secondary fluid is released via the atmospheric dump valves and main steam safety valves. Most of the released radiation is due to the ruptured tube. The 1 gpm primary to secondary LEAKAGE is relatively inconsequential.

The steam line break is more limiting for site radiation releases. The safety analysis for the steam line break accident assumes 1 gpm primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the steam line break accident are described in Reference 1, Section 14.14.

Reactor Coolant System operational LEAKAGE satisfies 10 CFR 50.36(c)(2)(ii), Criterion 2.

LCO

Reactor Coolant System operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment, can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with the detection of unidentified LEAKAGE and is well within the capability of the RCS makeup system. Identified LEAKAGE includes LEAKAGE to the Containment Structure from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled RCP seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One Steam Generator

The 100 gallon per day limit on primary to secondary LEAKAGE through any one SG is consistent with SG tube sleeving commitments.

APPLICABILITY

In MODEs 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODEs 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within four hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists or if unidentified, identified, or primary to secondary LEAKAGE cannot be reduced to within limits within four hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. The reactor must be brought to MODE 3 within 6 hours and to MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would first appear as unidentified LEAKAGE and can only be positively identified by inspection. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

The RCS water inventory balance must be performed with the reactor at steady-state operating conditions and near operating pressure.

Steady-state operation is required to perform a proper water inventory balance; calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady-state is defined as stable RCS

BASES

pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal leakoff flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. These leakage detection systems are specified in LCO 3.4.14.

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.13.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this surveillance test cannot be performed at normal operating conditions.

In the event one or more SGs are determined to not meet the requirements of the Steam Generator Tube Surveillance Program at anytime in MODEs 1 through 4, action to comply with LCO 3.0.3 must be taken.

REFERENCES

1. UFSAR
2. Regulatory Guide 1.45, Reactor Coolant Pressure Boundary Leakage Detection Systems, May 1973

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Cooling Systems provide containment atmosphere cooling to limit post-accident pressure and temperature in the Containment Structure to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray, reduce the release of fission product radioactivity from the Containment Structure to the environment, in the event of a DBA, to within limits. The Containment Spray and Cooling Systems are designed to the requirements in Reference 1, Appendix 1C, Criteria, 58, 59, 60, 61, 62, 63, 64, and 65.

The Containment Spray and Cooling Systems are ESF systems. They are designed to ensure that the heat removal capability required during the post-accident period can be attained. The Containment Spray and Cooling Systems provide redundant methods to limit and maintain post-accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains of equal capacity, each of sufficient capacity to supply approximately 50% of the design cooling requirement. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water tank (RWT) supplies borated water to the containment spray during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWT to the containment sump(s). Each spray system flow path from the containment sump will be via an OPERABLE shutdown cooling heat exchanger.

The Containment Spray System provides a spray of cold borated water into the upper regions of the Containment Structure to reduce containment pressure and temperature and to reduce the concentration of fission products in the containment atmosphere during a DBA. The RWT solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the shutdown cooling heat exchangers. Each train of the Containment Spray System provides adequate spray coverage to meet 50% of the system design requirements for containment heat removal and 100% of the iodine removal design bases.

The Containment Spray System is actuated either automatically by a containment spray actuation signal coincident with a SIAS or manually. An automatic actuation starts the two containment spray pumps, and begins the injection phase. The containment spray header isolation valves open upon a containment spray actuation signal. A manual actuation of the Containment Spray System is available on the main control board to begin the same sequence. The injection phase continues until an RWT low level signal is received. The low level for the RWT generates a recirculation actuation signal that aligns valves from the containment spray pump suction to the containment sump. The Containment Spray System in recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the Emergency Operating Procedures.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply approximately 67% of the design cooling requirement, are provided. Two trains with two fan units each are supplied with cooling water from a separate train of service water cooling. Three of the four fans are required to furnish the design cooling capacity. Air is drawn into the coolers through the fans and discharged throughout the Containment Structure.

In post-accident operation following a SIAS, all four Containment Cooling System fans are designed to start automatically in slow speed. Cooling is supplied by the service water cooled coils. The temperature of the service water is an important factor in the heat removal capability of the fan units.

BASES

APPLICABLE SAFETY ANALYSES

The Containment Spray and Cooling Systems limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered relative to containment temperature and pressure are LOCA and main SLB. The DBA, LOCA, and main SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train of the Containment Spray System and one train of the Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure and temperature are within the design. (See the Bases for Specifications 3.6.4 and 3.6.5 for a detailed discussion.) The analyses and evaluations assume a power level of 102% RATED THERMAL POWER, one containment spray train and one containment cooling train operating, and initial (pre-accident) conditions of 120°F and 16.5 psia. The analyses also assumes a response time delayed initiation, in order to provide a conservative calculation of peak containment pressure and temperature responses.

The modeled Containment Spray System actuation from the containment analysis is based upon a response time associated with exceeding the Containment High-High pressure setpoint coincident with an SIAS to achieve full flow through the containment spray nozzles. The Containment Spray System total response time of 60 seconds includes diesel generator startup (for loss of offsite power), sequencing equipment onto the emergency bus, containment spray pump startup, and spray line filling (Reference 1, Chapter 7).

The performance of the containment cooling train for post-accident conditions is given in Reference 1, Chapter 6. The results of the analysis, is that each train can provide approximately 67% of the required peak cooling capacity during the post-accident condition. The train post-accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 1, Chapter 6.

The modeled Containment Cooling System actuation from the containment analysis, is based upon the unit specific response time associated with exceeding the SIAS to achieve full Containment Cooling System air and safety grade cooling water flow.

The Containment Spray and Cooling Systems satisfy 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

During a DBA, a minimum of one containment cooling train and one containment spray train, is required to maintain the containment peak pressure and temperature, below the design limits (Reference 1, Chapter 6). Additionally, one containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and two containment cooling trains (all four coolers) must be OPERABLE. Therefore, in the event of an accident, the minimum requirements are met, assuming that the worst case single active failure occurs.

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWT upon an ESF actuation signal and automatically transferring suction to the containment sump. Each spray system flow path from the containment sump will be via an OPERABLE shutdown cooling heat exchanger.

Each Containment Cooling System includes cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODEs 1, 2, and 3, a DBA could cause a release of radioactive material to the Containment Structure and an increase in containment pressure and temperature, requiring the operation of the containment spray trains and containment cooling trains.

The Containment Spray System is only required to be OPERABLE in MODE 3 with pressurizer pressure ≥ 1750 psia.

In MODE 3 with pressurizer pressure < 1750 psia, and in MODEs 4, 5, and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODEs. Thus, the Containment Spray System is not required to be OPERABLE in MODE 3 with pressurizer pressure < 1750 psia, and the Containment Spray and Cooling Systems are not required to be OPERABLE in MODEs 4, 5, and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Specification 1.3, for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 3 with pressurizer pressure < 1750 psia within 12 hours. The allowed Completion Time of six hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner, and without challenging plant systems. The extended interval to reach MODE 3 with pressurizer pressure < 1750 psia allows additional time for the restoration of the containment spray train and is reasonable when considering that the driving force for a release of radioactive material from the RCS is reduced in MODE 3.

C.1

With one required containment cooling train inoperable, the inoperable containment cooling train must be restored to OPERABLE status within seven days. The remaining OPERABLE containment spray and cooling components provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The seven day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray and Cooling Systems, and the low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Specification 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

D.1

With two required containment cooling trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. The remaining OPERABLE containment spray components provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray and Cooling Systems, the iodine removal function of the Containment Spray System, and the low probability of a DBA occurring during this period.

E.1 and E.2

If the Required Actions and associated Completion Times of Conditions C or D of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With two containment spray trains or any combination of three or more Containment Spray and Cooling Systems trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to being secured. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation. Rather, it involves verifying, through a system walkdown, that those valves outside the Containment Structure and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.2

Starting each containment cooling train fan unit from the Control Room and operating it for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected and corrective action taken. The 31 day Frequency of this SR was developed considering the known reliability of the fan units and controls, the two train redundancy available, and the low probability of a significant degradation of the containment cooling train occurring between surveillances and has been shown to be acceptable through operating experience.

SR 3.6.6.3

Verifying a service water flow rate of ≥ 2000 gpm to each cooling unit when the full flow service water outlet valves are fully open provides assurance that the design flow rate assumed in the safety analyses will be achieved (Reference 1, Chapter 7). Also considered in selecting this Frequency were the known reliability of the Service Water System, the two train redundancy, and the low probability of a significant degradation of flow occurring between surveillance tests.

SR 3.6.6.4

Verifying that each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Reference 2. Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.6.5 and SR 3.6.6.6

These SRs verify that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation signal (i.e., the appropriate Engineered Safety Feature Actuation System signal). This SR is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The

BASES

24 month Frequency is based on the need to perform these surveillance tests under the conditions that apply during a plant outage and the potential for an unplanned transient if the surveillance tests were performed with the reactor at power. Operating experience has shown that these components usually pass the surveillance tests when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The surveillance test of containment sump isolation valves is also required by SR 3.5.2.5. A single surveillance test may be used to satisfy both requirements.

SR 3.6.6.7

This SR verifies that each containment cooling train actuates upon receipt of an actual or simulated actuation signal (i.e., the appropriate Engineered Safety Feature Actuation System signal). The 24 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.5 and SR 3.6.6.6, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.8

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through check valve bonnets. Performance of this SR demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the Containment Structure during an accident is not degraded. Due to the passive design of the nozzle, a test at ten year intervals is considered adequate to detect obstruction of the spray nozzles.

REFERENCES

1. UFSAR
2. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components"

B 3.7 PLANT SYSTEMS

B 3.7.6 Service Water (SRW) System

BASES

BACKGROUND

The SRW System provides a heat sink for the removal of process and operating heat from safety-related components during a DBA or transient. During normal operation or a normal shutdown, the SRW System also provides this function for various safety-related and non-safety-related components. The safety-related function is covered by this LCO.

The SRW System consists of two separate, 100% capacity safety-related cooling water subsystems. Each subsystem consists of a 100% capacity pump, head tank, two SRW heat exchangers, piping, valves, and instrumentation. A third pump, which is an installed spare, can be powered from either electrical train. The pumps and valves are remote manually aligned, except in the unlikely event of a LOCA. The pumps are automatically started upon receipt of a SIAS and all essential valves are aligned to their post-accident positions.

During normal operation, both subsystems are required, and are independent to the degree necessary to assure the safe operation and shutdown of the plant-assuming a single failure. During shutdown, operation of the SRW System is the same as normal operation, except that the heat loads are reduced. Additional information about the design and operation of the SRW System, along with a list of the components served, is presented in Reference 1, Section 9.5.2.2. In the event of a LOCA, the SRW System automatically realigns to isolate Turbine Building (non-safety-related) loads creating two independent and redundant safety-related subsystems. Service water flow to the spent fuel pool (SFP) cooler and the blowdown heat exchanger is automatically isolated as required for the DBA. Each SRW subsystem will supply cooling water to a diesel generator and two containment air coolers. However, the No. 11 SRW subsystem only supplies two containment air coolers since the No. 1A Diesel Generator is air cooled. Each SRW subsystem is sufficiently sized to remove the maximum amount of heat from the containment atmosphere while maintaining the SRW supply temperature to the diesel generator below its design limit.

APPLICABLE SAFETY ANALYSES

The design basis of the SRW System is for it to support a 100% capacity containment cooling system (containment coolers) and to remove core decay heat 36 minutes following a design basis LOCA, as discussed in Reference 1, Section 14.20. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the RCS by the safety injection pumps. The SRW System is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SRW System satisfies 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

Two SRW 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 single active failure occurs coincident with the loss of offsite power. Additionally, this system will also operate assuming that worst case passive failure post-RAS.

An SRW subsystem is considered OPERABLE when:

a. The associated pump and head tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety-related function are OPERABLE.

APPLICABILITY

In MODEs 1, 2, 3, and 4, the SRW System is a normally operating system, which is required to support the OPERABILITY of the equipment serviced by the SRW System and required to be OPERABLE in these MODEs.

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

BASES

ACTIONS

A.1 and A.2

With one SRW heat exchanger inoperable, action must be taken to restore operable status within 7 days. Isolating flow to one associated containment cooling unit will reduce the DBA heat load of the affected SRW subsystem to within the capacity of one SRW heat exchanger, thus ensuring that the SRW temperatures can be maintained within their design limits. This will allow the associated diesel generator (except for 11 SRW which does not cool a diesel generator) to remain operable. In this Condition, the other OPERABLE SRW System is adequate to perform the containment heat removal function. However, the overall reliability is reduced because a single failure in the SRW System could result in loss of SRW containment heat removal function. Required Action A.1 is modified by a Note. The Note indicates that the applicable Conditions of LCO 3.6.6 should be entered for an inoperable containment cooling train. The 7 day Completion Time is based on the redundant capabilities afforded by the OPERABLE subsystem, the Completion Time associated with an inoperable containment cooling unit (3.6.6), and the low probability of a DBA occurring during this time period.

B.1

With one SRW subsystem inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SRW System is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the SRW System could result in loss of SRW function. Required Action B.1 is modified by a Note. The Note indicates that the applicable Conditions of LCO 3.8.1, should be entered if the inoperable SRW subsystem results in an inoperable diesel generator. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE subsystem, and the low probability of a DBA occurring during this time period.

C.1 and C.2

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

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

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the SRW flow path ensures that the proper flow paths exist for SRW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This 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 is modified by a Note indicating that the isolation of the SRW components or systems may render those components inoperable but does not affect the OPERABILITY of the SRW System.

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

SR 3.7.6.2

This SR verifies proper automatic operation of the SRW System valves on an actual or simulated actuation signal (SIAS or CSAS). The SRW System is a normally operating system that cannot be fully actuated as part of normal testing. This surveillance test is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this surveillance test under the conditions that apply during a unit outage, and the potential for an unplanned transient if the surveillance test were performed with the reactor at

BASES

power. Operating experience has shown that these components usually pass the surveillance test when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.3

The SR verifies proper automatic operation of the SRW System pumps on an actual or simulated actuation signal (SIAS or CSAS). The SRW System is a normally operating system that cannot be fully actuated as part of the normal testing during normal operation. Operating experience has shown that these components usually pass the surveillance test when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR

B 3.7 PLANT SYSTEMS

B 3.7.7 Saltwater (SW) System

BASES

BACKGROUND

The SW System provides a heat sink for the removal of process and operating heat from safety-related components during a DBA or transient. During normal operation or a normal shutdown, the SW System also provides this function for various safety-related and non-safety-related components. The safety-related function is covered by this LCO.

The SW System consists of two subsystems. Each subsystem contains one pump. A third pump, which is an installed spare, can be aligned to either subsystem. The safety-related function of each subsystem is to provide SW to two SRW heat exchangers, a CC heat exchanger, and an Emergency Core Cooling System (ECCS) pump room air cooler in order to transfer heat from these systems to the bay. Seal water for the non-safety-related circulating water pumps is supplied by both or either subsystems. The SW pumps provide the driving head to move SW from the intake structure, through the system and back to the circulating water discharge conduits. The system is designed such that each pump has sufficient head and capacity to provide cooling water such that 100% of the required heat load can be removed by either subsystem.

During normal operation, both subsystems in each unit are in operation with one pump running on each header and a third pump in standby. If needed, the standby pumps can be lined-up to either supply header. The SW flow through the SRW and CC heat exchangers is throttled to provide sufficient cooling to the heat exchangers, while maintaining total subsystem flow below a maximum value.

Additional information about the design and operation of the SW System, along with a list of the components served, is presented in Reference 1. During an accident, the SW System is required to remove the heat load from the SRW and ECCS pump room, and from the CC following an RAS.

APPLICABLE SAFETY ANALYSES

The most limiting event for the SW System is a LOCA. Operation of the SW System following a LOCA is separated into two phases, before the RAS and after the RAS. One subsystem can satisfy cooling requirements of both phases. After a LOCA but before an RAS, each subsystem will cool two SRW heat exchangers and an ECCS pump room air cooler (as required). There is no flow to the CC heat exchangers. When an RAS occurs, flow is initiated to the CC heat exchanger. Flow to each SRW heat exchanger is reduced while the system remains capable of providing the required flow to the ECCS pump room air coolers.

The SW System satisfies 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

Two SW 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 single active failure occurs coincident with the loss of offsite power. Additionally, this system will also operate assuming the worst case passive failure post-RAS.

An SW subsystem is considered OPERABLE when:

a. The associated pump is OPERABLE; and

b. The associated piping, valves, heat exchangers, and instrumentation and controls required to perform the safety-related function are OPERABLE.

APPLICABILITY

In MODEs 1, 2, 3, and 4, the SW System is a normally operating system, which is required to support the OPERABILITY of the equipment serviced by the SW System and required to be OPERABLE in these MODEs.

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

ACTIONS

A.1

With one SW subsystem inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the SW subsystem could result in loss of SW System function. Required Action A.1 is modified by two Notes. The first Note indicates that the applicable Conditions of LCO 3.8.1 should be entered if the inoperable SW subsystem results in an inoperable emergency diesel generator. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6 should be entered if an inoperable SW subsystem results in an inoperable SDC. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

B.1 and B.2

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

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

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Verifying the correct alignment for manual, power-operated, and automatic valves in the SW System flow path ensures that the proper flow paths exist for SW System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This surveillance test 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 is modified by a Note indicating that the isolation of the SW System components or systems may render those components inoperable but does not affect the OPERABILITY of the SW System.

BASES

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

SR 3.7.7.2

This SR verifies proper automatic operation of the SW System valves on an actual or simulated actuation signal (SIAS). The SW System is a normally operating system that cannot be fully actuated as part of the normal testing. This surveillance test is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this surveillance test under the conditions that apply during a unit outage and the potential for an unplanned transient if the surveillance test were performed with the reactor at power. Operating experience has shown that these components usually pass the surveillance test when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

The SR verifies proper automatic operation of the SW System pumps on an actual or simulated actuation signal (SIAS). The SW System is a normally operating system that cannot be fully actuated as part of the normal testing during normal operation. Operating experience has shown that these components usually pass the surveillance test when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 9.5.2.3, "Saltwater System"

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The AC sources to the Class 1E Electrical Power Distribution System consist of the offsite power sources starting at the 4.16 kV engineered safety feature (ESF) buses and the onsite diesel generators (DGs). As required by Reference 1, General Design Criteria (GDC) 17, the design of the AC electrical power system has sufficient independence and redundancy to ensure a source to the ESFs assuming a single failure.

The Class 1E AC Distribution System is divided into two redundant load groups so that the loss of one group does not prevent the minimum safety functions from being performed. Each load group has connections to two offsite sources and one Class 1E DG at its 4.16 kV 1E bus.

Offsite power is supplied to the 500 kV Switchyard from the transmission network by three 500 kV transmission lines. Two electrically and physically separated circuits supply electric power from the 500 kV Switchyard to two 13 kV buses and then to the two 4.16 kV ESF buses. A third 69 kV/ 13.8 kV offsite power source that may be manually connected to either 13 kV bus is available from the Southern Maryland Electric Cooperative (SMECO). When appropriate, the Engineered Safety Feature Actuation System (ESFAS) loss of coolant incident and shutdown sequencer for the 4.16 kV bus will sequence loads on the bus after the 69 kV/13.8 kV SMECO line has been manually placed in service. The SMECO offsite power source will not be used to carry loads for an operating unit. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses, is found in Reference 2, Chapter 8.

The required offsite power circuits are the two 13 kV buses (Nos. 11 and 21) which can be powered by:

a. Two 500 kV lines, two 500 kV buses each of which have connections to a 500 kV line that does not pass through the other 500 kV bus and both P-13000 (500 kV/14 kV) transformers; or

b. One 500 kV line, one 500 kV bus, and one associated P-13000 (500 kV/14 kV) transformer, and the 69 kV/ 13.8 kV SMECO line. When the SMECO line is credited as one of the qualified offsite circuits, the disconnect from the SMECO line to Warehouse No. 1 must be open.

In addition, each offsite circuit includes the cabling to and from a 13.8/13.8 voltage regulator, the voltage regulator, 13.8/4.16 kV unit service transformer, the unit service transformer, and one of the two breakers to one 4.16 kV ESF bus. Transfer capability between the two required offsite circuits is by manual means only. The required circuit breaker to each 4.16 kV ESF bus must be from different 13.8/4.16 unit service transformers for the two required offsite circuits. Thus, each unit is able to align one 4.16 kV bus to one required offsite circuit, and the other 4.16 kV bus to the other required offsite circuit.

In some cases, inoperable components in the electrical circuit place both units in Conditions. Examples of these are 13.8 kV bus Nos. 11 or 21, two 500 kV transmission lines, one P-13000 service transformer, or one 500 kV bus. In other cases, inoperable components only place one unit in a Condition, such as an inoperable U-4000 and/or 13.8 kV regulator that feeds a required 4.16 kV bus.

The onsite standby power source to each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on an safety injection actuation signal or on a 4.16 kV degraded or undervoltage signal. If both 4.16 kV offsite source breakers are open, the DG, after reaching rated voltage and frequency, will automatically close onto the 4.16 kV bus.

In the event of a loss of offsite power to a 4.16 kV 1E bus, if required, the ESF electrical loads will be automatically sequenced onto the DG in sufficient time to provide for safe shutdown for an anticipated operational occurrence (AOO) and to ensure that the containment integrity and other vital functions are maintained in the event of a design bases accident.

BASES

Ratings for the No. 1A DG satisfies the requirements of Reference 3 and ratings for the Nos. 1B, 2A, and 2B DGs satisfy the requirements of Reference 4. The continuous service rating for the No. 1A DG is 5400 kW and for the Nos. 1B, 2A, and 2B DGs are 3000 kW.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Reference 1, Chapters 6 and 14, 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, RCS, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Sections 3.2, 3.4, and 3.6.

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

a. An assumed loss of all offsite power; and

b. A single failure.

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

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power Distribution System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

Qualified offsite circuits are those that are described in the Updated Final Safety Analysis Report (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 ESF buses. Loads are immediately connected to the ESF buses when the buses are powered from the 500 kV offsite circuits and, when powered from the 69/13.8 kV SMECO offsite circuit after being manually connected, the loads are sequenced onto the ESF bus utilizing the same sequencer used to sequence the loads onto the DG. The SMECO offsite circuit will not be used to carry loads for an operating unit.

The Limiting Condition for Operation (LCO) requires operability of two out of three qualified circuits between the transmission network and the onsite Class 1E AC Electrical Power Distribution System circuits. These circuits consist of two 500 kV circuits via 500 kV/14 kV and 13.8 kV/4.16 kV transformers and the 69 kV SMECO dedicated source (described in Reference 5) via 69 kV/ 13.8 kV and 13.8 kV/4.16 kV transformers. In addition, each offsite circuit includes one of the two breakers to one 4.16 kV ESF bus. The required circuit breaker to each 4.16 kV ESF bus must be from different 13.8/4.16 unit service transformers for the two required offsite circuits. Thus, each unit is able to align one 4.16 kV bus to one required offsite circuit, and the other 4.16 kV bus to the other required offsite circuit.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to reject a load ≥ 500 hp without tripping.

Proper sequencing of loads, including shedding of non-essential loads, is a required function for DG OPERABILITY in MODEs 1, 2, and 3.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other

BASES

train. For the DGs, separation and independence are complete.

The Control Room Emergency Ventilation System (CREVS) Control Room Emergency Temperature System (CRETS), and H_2 Analyzer are shared systems with one train of each system connected to an onsite Class 1E AC electrical power distribution subsystem from each unit. Limiting Condition for Operation 3.8.1.c requires one qualified circuit between the offsite transmission network and the other unit's onsite Class 1E AC electrical power distribution subsystems needed to supply power to the CREVS, CRETS, and H_2 Analyzer to be OPERABLE and one DG from the other unit capable of supplying power to the CREVS, CRETS, and H_2 Analyzer to be OPERABLE. The qualified circuit in LCO 3.8.1.c must be separate and independent (to the extent possible) of the qualified circuit which provides power to the other train of the CREVS, CRETS, and H_2 Analyzer. These requirements, in conjunction with the requirements for the unit AC electrical power sources in LCO 3.8.1.a and LCO 3.8.1.b, ensure that power is available to two trains of the CREVS, CRETS, and H_2 Analyzer.

APPLICABILITY

The AC sources are required to be OPERABLE in MODEs 1, 2, 3, and 4 to ensure that:

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

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

The AC power requirements for MODEs 5 and 6 are covered in LCO 3.8.2.

ACTIONS

A.1

To ensure a highly reliable power source remains with the one required LCO 3.8.1.a offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of

Surveillance Requirement (SR) 3.8.1.1 or SR 3.8.1.2 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1 or SR 3.8.1.2, the second offsite circuit is inoperable, and Condition C and/or E, as applicable, for the two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power train(s). Single train systems may not be included.

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

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

b. A required feature on another train is inoperable.

If at any time during the existence of Condition A (one required LCO 3.8.1.a offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

The Completion Time must be started if it is discovered that there is no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features (or both) that are associated with the other train that has offsite power. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

Consistent with Reference 6, operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or LCO 3.8.1.b. If Condition A is entered while, for instance, an LCO 3.8.1.b DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet LCO 3.8.1.a or LCO 3.8.1.b, to restore the offsite circuit. At this time, a LCO 3.8.1.b DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of nine days) allowed prior to complete restoration of LCOs 3.8.1.a and 3.8.1.b. The six day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet

LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and six day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with an inoperable LCO 3.8.1.b DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 or SR 3.8.1.2 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1 or SR 3.8.1.2, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a LCO 3.8.1.b DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety-related trains. Single train systems are not included. Redundant required feature failures consist of inoperable features with a train, redundant to the train that has an inoperable LCO 3.8.1.b DG.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required

Action, the Completion Time only begins on discovery that both:

a. An inoperable LCO 3.8.1.b DG exists; and

b. A required feature on another train is inoperable.

If at any time during the existence of this Condition (one LCO 3.8.1.b DG inoperable) a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required LCO 3.8.1.b DG inoperable coincident with one or more inoperable required support or supported features (or both) that are associated with the OPERABLE DGs, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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

<u>B.3.1 and B.3.2</u>

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.3 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition D and/or G of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.3 suffices to provide assurance of continued OPERABILITY of the DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the 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.

Consistent with Reference 7, 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

Consistent with Reference 6, operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or LCO 3.8.1.b. If Condition B is entered while, for instance, an LCO 3.8.1.a offsite circuit is inoperable and that circuit is subsequently returned OPERABLE, the LCO may already have not been met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet LCO 3.8.1.a or LCO 3.8.1.b, to restore the DG. At this time, a LCO 3.8.1.a offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of nine days) allowed prior to complete restoration of LCO 3.8.1.a and LCO 3.8.1.b. The six day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and six day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition B was entered.

C.1

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it, were inoperable resulting in de-energization. Therefore, the Required Actions of Condition C are modified by a Note to indicate that when Condition C is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, must be immediately entered. This allows Condition C to provide requirements for the loss of the LCO 3.8.1.c offsite circuit and DG without regard to whether a train is de-energized. Limiting Condition for Operation 3.8.9 provides the appropriate restrictions for a de-energized train.

To ensure a highly reliable power source remains with the one required LCO 3.8.1.c offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 or SR 3.8.1.2 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1 or SR 3.8.1.2, the second offsite circuit is inoperable, and Condition A and/or E, as applicable, for the two offsite circuits inoperable, is entered.

C.2

Required Action C.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function for the CREVS, CRETS, or the H_2 Analyzers. The Completion Time for Required Action C.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

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

b. A train of CREVS, CRETS, or H_2 Analyzer on the other train is inoperable.

If at any time during the existence of Condition C (one required LCO 3.8.1.c offsite circuit inoperable) a train of CREVS, CRETS, or H_2 Analyzer becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one train of CREVS, CRETS or H_2 Analyzer that is associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable CREVS, CRETS, or H_2 Analyzer. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

<u>C.3</u>

Consistent with the time provided in ACTION A, operation may continue in Condition C for a period that should not exceed 72 hours. With one required LCO 3.8.1.c offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

If the LCO 3.8.1.c required offsite circuit cannot be restored to OPERABLE status within 72 hours, the CREVS, CRETS, and H_2 Analyzer associated with the offsite circuit must be declared inoperable. The ACTIONS associated with the CREVS, CRETS, and H_2 Analyzer will ensure the appropriate actions are taken. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

D.1

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it, were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9 must be immediately entered. This allows Condition D to provide requirements for the loss of the LCO 3.8.1.c offsite circuit and DG without regard to whether a train is de-energized. Limiting Condition for Operation 3.8.9 provides the appropriate restrictions for a de-energized train.

To ensure a highly reliable power source remains with the one required LCO 3.8.1.c DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequency basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 or SR 3.8.1.2 acceptance criteria does not result in a Required Action not met. However, if a circuit fails to pass SR 3.8.1.1 or SR 3.8.1.2, it is inoperable. Upon offsite circuit inoperability additional Conditions and Required Actions must then be entered.

D.2

Required Action D.2 is intended to provide assurance that a loss of offsite power, during the period the LCO 3.8.1.c DG is inoperable, does not result in a complete loss of safety function for the CREVS, CRETS, or the H_2 Analyzers. The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable LCO 3.8.1.c DG exists; and

b. A train of CREVS, CRETS, or H_2 Analyzers on the other train is inoperable.

If at any time during the existence of this Condition (the LCO 3.8.1.c DG inoperable) a train of CREVS, CRETS, or H_2 Analyzer becomes inoperable, this Completion Time begins to be tracked.

Discovering the LCO 3.8.1.c DG inoperable coincident with one train of CREVS, CRETS, or H_2 Analyzer that is associated with the one LCO 3.8.1.b 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.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the CREVS, CRETS, or H_2 Analyzer may have been lost; however, function has not been lost. The four hour Completion Time also takes into account the capacity and capability of the remaining CREVS, CRETS, and H_2 Analyzer train, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

D.3.1 and D.3.2

Required Action D.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.3 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition B and/or F of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action D.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.3 suffices to provide assurance of continued OPERABILITY of the DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either D.3.1 or D.3.2, the 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 D.

Consistent with Reference 6, 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

D.4

Consistent with the time provided in ACTION B, operation may continue in Condition D for a period that should not exceed 72 hours. In Condition D, the remaining OPERABLE DGs and offsite power circuits are adequate to supply electrical power to the Class 1E Distribution System.

If the LCO 3.8.1.c DG cannot be restored to OPERABLE status within 72 hours the CREVS, CRETS, and H_2 Analyzer associated with this DG must be declared inoperable. The Actions associated with the CREVS, CRETS, and H_2 Analyzer will ensure the appropriate Actions are taken.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1 and E.2

Condition E is entered when both offsite circuits required by LCO 3.8.1.a are inoperable, or when the offsite circuit required by LCO 3.8.1.c and one offsite circuit required by LCO 3.8.1.a are concurrently inoperable, if the LCO 3.8.1.a offsite circuit is credited with providing power to the CREVS, CRETS, and H_2 Analyzer.

Required Action E.1 is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Reference 6 allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. Single train features are not included in the list.

The Completion Time for Required Action E.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. Two required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition E (e.g., two required LCO 3.8.1.a offsite circuits inoperable) and a required feature becomes inoperable, this Completion Time begins to be tracked.

Consistent with Reference 6, operation may continue in Condition E 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 could correspond to a total loss of the immediately accessible offsite power sources.

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

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 two of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a loss of coolant accident, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

Consistent with Reference 6, with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is required within 24 hours, power operation continues in accordance with Condition A or C, as applicable.

F.1 and F.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition F are modified by a Note to indicate that when Condition F is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, must be immediately entered. This allows Condition F to provide requirements for the loss of one required LCO 3.8.1.a offsite circuit and one LCO 3.8.1.b DG without regard to whether a train is de-energized. Limiting Condition for Operation 3.8.9 provides the appropriate restrictions for a de-energized train.

Consistent with Reference 6, operation may continue in Condition F for a period that should not exceed 12 hours.

In Condition F, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition F (loss of two required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

G.1

With two LCO 3.8.1.b DGs inoperable, there are no remaining standby AC sources to provide power to most of the ESF systems. With one LCO 3.8.1.c DG inoperable and the LCO 3.8.1.b DG that provides power to the CREVS, CRETS, and H_2 Analyzer inoperable, there are no remaining standby AC sources to the CREVS, CRETS, and H_2 Analyzers. 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 this level of degradation, the risk associated with continued operation for a short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

Consistent with Reference 6, with both LCO 3.8.1.b DGs inoperable, or with the LCO 3.8.1.b DG that provides power to the CREVS, CRETS, and H_2 Analyzer and the LCO 3.8.1.c DG inoperable, operation may continue for a period that should not exceed 2 hours.

H.1 and H.2

If any Required Action and associated Completion Time of Conditions A, B, E, F, or G are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within six hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

I.1

Condition I corresponds to a level of degradation in which all redundancy in LCO 3.8.1.a and LCO 3.8.1.b AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with Reference 1, GDC 18. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Reference 3, or Reference 4, and Reference 8.

When the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum transient output voltage of 3740 V is 90% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. The specified maximum output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to +/- 2% of the 60 Hz nominal frequency and are the recommendations given in Reference 3.

The SRs are modified by a Note which states that SR 3.8.1.1 through SR 3.8.1.15 are applicable to LCO 3.8.1.a and LCO 3.8.1.b AC Sources. The Note also states that SR 3.8.1.16 is applicable to LCO 3.8.1.c AC sources. This Note clarifies that not all of the SRs are applicable to all the components described in the LCO.

<u>SR 3.8.1.1 and SR 3.8.1.2</u>

These SRs assure proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The Frequency of once within one hour after substitution for a 500 kV circuit and every eight hours thereafter, for SR 3.8.1.1 was established to ensure that the breaker alignment for the SMECO circuit (which does not have Control Room indication) is in its correct position although breaker position is unlikely to change. The seven day Frequency for SR 3.8.1.2 is adequate since the 500 kV circuit breaker position is not likely to change without the operator being aware of it and because its status is displayed in the Control Room.

Surveillance Requirement 3.8.1.1 is modified by a Note which states that this SR is only required when SMECO is being credited for an offsite source. This SR will prevent unnecessary testing on an uncredited circuit.

SR 3.8.1.3 and SR 3.8.1.9

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.3) to indicate that all DG starts for these surveillance tests may be preceded by an engine prelube period and followed by a warmup period prior to loading by an engine prelube period.

For the purposes of SR 3.8.1.9 testing, the DGs are required to start from standby conditions only for SR 3.8.1.9. Standby conditions for a DG mean 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 mechanical wear on diesel engines, the DG manufacturers recommend a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. This is the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

Surveillance Requirement 3.8.1.9 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. The

10 second start requirement supports the assumptions of the design basis loss of coolant accident analysis in Reference 2, Chapter 14.

Since SR 3.8.1.9 requires a 10 second start, it is more restrictive than SR 3.8.1.3, and it may be performed in lieu of SR 3.8.1.3.

The 31 day Frequency for SR 3.8.1.3 is consistent with Reference 4 and Reference 3. The 184 day Frequency for SR 3.8.1.9 is a reduction in cold testing consistent with Reference 7. This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.4

This SR verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to 4000 kW for No. 1A DG and greater than or equal to 90% of the continuous duty rating for the remaining DGs. The 90% minimum load limit is consistent with Reference 3 and is acceptable because testing of these DGs at post-accident load values is performed by SR 3.8.1.11. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation. The 31-day Frequency for this SR is consistent with Reference 3.

This SR is modified by four Notes. Note 1 indicates that the diesel engine runs for this surveillance test may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Note 3 indicates that this surveillance test shall be conducted on only one DG at a time in order to prevent routinely paralleling multiple DGs and to minimize the potential for effects from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.5

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level required by the SR is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of one hour of DG operation at full load plus 10%.

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

SR 3.8.1.6

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is 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 accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The SR Frequencies are consistent with Reference 8. This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this surveillance test.

SR 3.8.1.7

This SR demonstrates that one fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This SR 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 automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days. The 31-day Frequency corresponds to the design of the fuel transfer system. The design of fuel transfer systems is such that pumps will operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. In such a case, a 31-day Frequency is appropriate.

SR 3.8.1.8

Under accident and loss of offsite power conditions loads are sequentially connected to the bus by the automatic load sequencer (this SR verifies steps 1 through 5). The sequencing logic controls the permissive and closing signals to breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load, and that safety analysis assumptions regarding ESF equipment time delays are not violated. The UFSAR provides a summary of the automatic loading of ESF buses.

The Frequency of 31 days is consistent with DG monthly testing and is sufficient to ensure the load sequencer operation as required.

SR 3.8.1.9

See SR 3.8.1.3.

SR 3.8.1.10

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit 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.

SR 3.8.1.11

This SR provides verification that the DG can be operated at a load greater than predicted accident loads for at least 60 minutes once per 24 months. Operation at the greater than calculated accident loads will clearly demonstrate the ability of the DGs to perform their safety function. In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a DG load greater than or equal to calculated accident load and using a power factor ≤ 0.85. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. In addition, the post-accident load for No. 1A DG is significantly lower than the continuous rating of No. 1A DG. To ensure No. 1A DG performance is not degraded, routine monitoring of engine parameters should be performed during the performance of this SR for No. 1A DG (Reference 9).

This SR is modified by a Note which states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit will not invalidate the test. The 24 month Frequency is adequate to ensure DG OPERABILITY and it is consistent with the refueling interval.

SR 3.8.1.12

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 SR demonstrates the DG load response characteristics. This SR is accomplished by tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power.

Consistent with References 10, 3, and 4, 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.

The 24 month Frequency is consistent with the Reference 2, Chapter 8.

SR 3.8.1.13

This SR demonstrates that DG non-critical protective functions are bypassed on a required actuation signal. This SR is accomplished by verifying the bypass contact changes to the correct state which prevents actuation of the non-critical function. The non-critical protective functions are consistent with References 3 and 4, and Institute of Electrical and Electronic Engineers (IEEE)-387 and are listed in Reference 2, Chapter 8. Verifying the non-critical trips are bypassed will ensure DG operation during a required actuation. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. A failure of the electronic governor results in the diesel generator operating in hydraulic mode. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance test, 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 Frequency is consistent with Reference 2, Chapter 8.

SR 3.8.1.14

This SR 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 load sequence timers are reset.

The Frequency of 24 months takes into consideration unit conditions required to perform the surveillance test.

SR 3.8.1.15

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 SR demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF (i.e., safety injection) actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

It is not necessary to energize loads which are dependent on temperature to load (i.e., heat tracing, switchgear HVAC compressor, computer room HVAC compressor). Also, it is acceptable to transfer the instrument AC bus to the non tested train to maintain safe operation of the plant during testing. Loads (both permanent and auto connect) < 15 kW do not require loading onto the diesel since these are insignificant loads for the DG.

The Frequency of 24 months takes into consideration unit conditions required to perform the surveillance test and is intended to be consistent with an expected fuel cycle length of 24 months.

This SR is modified by a Note. The reason for the Note is to minimize mechanical wear and stress on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs.

SR 3.8.1.16

This SR lists the SRs that are applicable to the LCO 3.8.1.c (SRs 3.8.1.1, 3.8.1.2, 3.8.1.3, 3.8.1.5, 3.8.1.6, and 3.8.1.7). Performance of any SR for the LCO 3.8.1.c will satisfy both Unit 1 and Unit 2 requirements for those SRs. Surveillance Requirements 3.8.1.4, 3.8.1.8, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.13, 3.8.1.14, and 3.8.1.15, are not required to be performed for the LCO 3.8.1.c. Surveillance Requirement 3.8.1.10 is not required because this SR verifies manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit, but only one qualified offsite circuit is necessary for the LCO 3.8.1.c. Surveillance Requirements 3.8.1.4, 3.8.1.11, and 3.1.8.12 are not required because they are tests that deal with loads. Surveillance Requirement 3.8.1.8 verifies the interval between sequenced loads. Surveillance Requirement 3.8.1.14 verifies the proper sequencing with offsite power. Surveillance Requirement 3.8.1.9 verifies that the DG starts within 10 seconds. These SRs are not required because they do not support the function of the LCO 3.8.1.c to provide power to the CREVS, CRETS, and H_2 Analyzer. Surveillance Requirements 3.8.1.13 and 3.8.1.15 are not required to be performed because these SRs verify the emergency loads are actuated on an ESFAS signal for the Unit in which the test

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is being performed. The LCO 3.8.1.c DG will not start on an ESFAS signal for this Unit.

REFERENCES

1. 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants"
2. UFSAR
3. Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," July 1993
4. Safety Guide 9, Revision 0, March 1971
5. NRC Safety Evaluation for Amendment Nos. 19 and 5 for Calvert Cliffs Nuclear Power Plant Unit Nos. 1 and 2, dated January 14, 1977
6. Regulatory Guide 1.93, Revision 0, "Availability of Electric Power Sources," December 1974
7. Generic Letter 84-15, Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability, July 2, 1984
8. Regulatory Guide 1.137, Revision 1, "Fuel-Oil Systems for Standby Diesel Generators," October 1979
9. Letter from Mr. D. G. McDonald, Jr. (NRC) to Mr. C. H. Cruse (BGE), dated April 2, 1996, Issuance of Amendments for Calvert Cliffs Nuclear Power Plant, Unit 1 (TAC No. M94030) and Unit 2 (TAC No. M94031)
10. IEEE Standard 308-1991, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations"

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources-Shutdown

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BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1.

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODEs 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many DBAs that are analyzed in MODEs 1, 2, 3, and 4 have no specific analyses in MODEs 5 and 6. Worst case bounding events are deemed not credible in MODEs 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODEs 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODEs 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODEs 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODEs 1, 2, 3, and 4 LCO requirements are acceptable during shutdown MODEs based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODEs 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite DG power.

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

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with a distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF bus(es). Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

The DG must be capable of starting, accelerating to rated speed and voltage, connecting to its respective ESF bus, and accepting required loads. The DG must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby at ambient conditions.

It is acceptable for trains to be cross-tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

The CREVS and CRETS are shared systems with one train of each system connected to an onsite Class 1E AC electrical power distribution subsystem from each unit. Limiting Condition for Operation 3.8.2.c requires one qualified circuit between the offsite transmission network and the other unit's onsite Class 1E AC electrical power distribution subsystems needed to supply power to the CREVS and CRETS to be OPERABLE. Limiting Condition for Operation 3.8.2.d requires one DG from the other unit capable of supplying power to the required CREVS and CRETS to be OPERABLE, if the DG required by LCO 3.8.2.b is not capable of supplying power to the required CREVS and CRETS. These requirements, in conjunction with the requirements for the unit AC electrical power sources in LCO 3.8.2.a and LCO 3.8.2.b, ensure that offsite power is available to both trains and onsite power is available to one train of the CREVS and CRETS, when they are required to be OPERABLE by their respective LCOs (LCOs 3.7.8 and 3.7.9).

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APPLICABILITY

The AC sources required to be OPERABLE in MODEs 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODEs 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

Limiting Condition for Operation 3.0.3 is not applicable while in MODEs 5 or 6. However, since irradiated fuel assembly movement can occur in MODEs 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODEs 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODEs 1, 2, 3, or 4, 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.

The ACTIONS have been modified by a second Note stating that performance of Required Actions shall not preclude completion of actions to establish a safe conservative position. This clarification is provided to avoid stopping movement of irradiated fuel assemblies while in a non-conservative position based on compliance with the Required Actions.

A.1

An offsite circuit would be considered inoperable, if it was unavailable to one required ESF train. Although two trains may be required by LCO 3.8.10, the remaining train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SHUTDOWN MARGIN (SDM) is maintained.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required, to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Electrical Distribution System's ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the

Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. Limiting Condition for Operation 3.8.10 provides the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 and SR 3.8.2.2

Surveillance Requirements 3.8.2.1 and 3.8.2.2 require the performance of SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODEs 1, 2, 3, and 4. Surveillance Requirement 3.8.1.10 is not required to be met, since only one offsite circuit is required to be OPERABLE. Surveillance Requirements 3.8.1.4, 3.8.1.8, 3.8.1.13, and 3.8.1.15 are related to automatic starting of the DGs for an operating unit, which is not applicable for a shutdown unit. Surveillance Requirement 3.8.1.16 is related to LCO 3.8.2.c and 3.8.2.d AC sources, and is addressed by SR 3.8.2.2.

Surveillance Requirement 3.8.2.1 is modified by a Note. The Note lists SRs not required to be performed in order to preclude de-energizing a required 4.16 kV ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC Sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit are required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems-Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus Electrical Power Distribution Systems are divided into two redundant and independent AC electrical power distribution subsystems and four independent and redundant DC and AC vital bus electrical power distribution subsystems (Reference 1, Chapter 8).

The AC primary Electrical Power Distribution System consists of two 4.16 kV ESF buses, each having at least one separate and independent offsite source of power as well as a dedicated onsite DG source. Each 4.16 kV ESF bus is normally connected to a preferred offsite source. After a loss of the preferred offsite power source to a 4.16 kV ESF bus, the onsite emergency DG supplies power to the 4.16 kV ESF bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCOs 3.8.1 and 3.8.4.

The 480 V system include the safety-related load centers, motor control centers, and distribution panels shown in Table B 3.8.9-1.

The 120 VAC vital buses are divided into four independent and isolated subsystems and are normally supplied from an inverter. The alternate power supply for the vital buses are non-Class 1E 120 VAC Buses fed from a Class 1E ESF motor control center through the regulating transformer, and its use is governed by LCO 3.8.7. Each constant voltage source transformer is powered from a Class 1E AC bus.

There are four independent 125 VDC electrical power distribution subsystems.

The list of all required Distribution Systems-Operating is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in Reference 1, Chapters 6 and 14, assume ESF systems are OPERABLE. The AC, DC, and AC vital bus Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Sections 3.2, 3.4, and 3.6.

The OPERABILITY of the AC, DC, and AC vital bus Electrical Power Distribution Systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The distribution systems satisfy 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

The required electrical power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical supply for the systems required to shut down the reactor and maintain it in a safe condition after an AOO or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical distribution subsystems require the associated buses to be energized to their proper voltage.

In addition, tie breakers between redundant safety-related AC, DC, and AC vital bus distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any 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 affected redundant electrical distribution subsystems are considered inoperable. This applies to the onsite, safety-related redundant electrical power distribution subsystems.

APPLICABILITY

The electrical distribution subsystems are required to be OPERABLE in MODEs 1, 2, 3, and 4 to ensure that:

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

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

Electrical distribution subsystem requirements for MODEs 5 and 6 are covered in the Bases for LCO 3.8.10.

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except AC vital buses, inoperable 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 eight hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The eight hour time limit before requiring a unit shutdown in this condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to two hours. This could lead to a total of ten hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

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

B.1

With one or more AC vital buses inoperable and a loss of Function has not yet occurred, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the AC vital bus must be restored to OPERABLE status within two hours by powering the bus from an associated inverter via DC or the non-Class 1E 120 VAC bus powered by an ESF motor control center through a regulating transformer.

Condition B represents one or more AC vital buses without power; potentially both the DC source and the associated AC source are non-functioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital buses, and restoring power to the affected vital bus.

This two hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, which would have the Required Action Completion Times shorter than two hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The two hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of 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 returned OPERABLE, the LCO may already have been not met for up to eight hours. This could lead to a total of ten hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution 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 will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

<u>C.1</u>

With one DC bus inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the DC bus must be restored to OPERABLE status within two hours by powering the bus from the associated battery or charger.

Condition C represents one DC bus without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This two hour limit is more conservative than Completion Times allowed for the vast majority of components which would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The two hour Completion Time for DC buses is consistent with Reference 2.

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have not been met for up to eight hours. This could lead to a total of ten hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution 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 will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution 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 six hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

E.1

Condition E corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one inoperable electrical power distribution subsystem results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. Limiting Condition for Operation 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This SR verifies that the AC, DC, and AC vital bus Electrical Power Distribution Systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system

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loads connected to these buses. The seven day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the Control Room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR
2. Regulatory Guide 1.93, "Availability of Electric Power Sources," December 1974

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems[1]

4160 Volt Emergency Bus No. 11 (Unit 1), No. 21 (Unit 2)
4160 Volt Emergency Bus No. 14 (Unit 1), No. 24 (Unit 2)
480 Volt Emergency Bus No. 11A (Unit 1), No. 21A (Unit 2)
480 Volt Emergency Bus No. 11B (Unit 1), No. 21B (Unit 2)
480 Volt Emergency Bus No. 14A (Unit 1), No. 24A (Unit 2)
480 Volt Emergency Bus No. 14B (Unit 1), No. 24B (Unit 2)
480 Volt Emergency Bus No. 104R (Unit 1), No. 204R (Unit 2)
480 Volt Emergency Bus No. 114R (Unit 1), No. 214R (Unit 2)
120 Volt AC Vital Bus No. 11 (Unit 1), No. 21 (Unit 2)
120 Volt AC Vital Bus No. 12 (Unit 1), No. 22 (Unit 2)
120 Volt AC Vital Bus No. 13 (Unit 1), No. 23 (Unit 2)
120 Volt AC Vital Bus No. 14 (Unit 1), No. 24 (Unit 2)
125 Volt DC Bus No. 11 (Unit 1 and Unit 2)
125 Volt DC Bus No. 12 (Unit 1 and Unit 2)
125 Volt DC Bus No. 21 (Unit 1 and Unit 2)
125 Volt DC Bus No. 22 (Unit 1 and Unit 2)

(1) Each bus of the AC and DC Electrical Power Distribution System is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems-Shutdown

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BACKGROUND	A description of the AC, DC, and AC vital bus Electrical Power Distribution Systems is provided in the Bases for LCO 3.8.9. The list of all required Distribution Systems-Shutdown is presented in Table B 3.8.10-1.
APPLICABLE SAFETY ANALYSES	The initial conditions of a DBA and transient analyses in Reference 1, Chapters 6 and 14, assume ESF systems are OPERABLE. The AC, DC, and AC vital bus Electrical Power Distribution Systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. The OPERABILITY of the AC, DC, and AC vital bus Electrical Power Distribution System is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power distribution subsystems during MODEs 5 and 6, and during movement of irradiated fuel assemblies, ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident. The AC and DC Electrical Power Distribution Systems satisfy 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific unit condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components-all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODEs 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystem requirements for MODEs 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

Limiting Condition for Operation 3.0.3 is not applicable while in MODEs 5 or 6. However, since irradiated fuel assembly movement can occur in MODEs 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODEs 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODEs 1, 2, 3, or 4, 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.

The ACTIONS have been modified by a second Note stating that performance of Required Actions shall not preclude completion of actions to establish a safe conservative position. This clarification is provided to avoid stopping movement of irradiated fuel assemblies while in a non-conservative position based on compliance with the Required Actions.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystems LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

Suspension of these activities 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 unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required shutdown cooling (SDC) subsystem may be inoperable. In this case, Required

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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 SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring SDC inoperable, which results in taking the appropriate SDC actions. The SDC subsystem(s) declared inoperable and not in operation as a result of not meeting this LCO, may be used if needed. However, the appropriate actions are still required to be taken.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This SR verifies that the AC, DC, and AC vital bus Electrical Power Distribution System is functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The seven day Frequency takes into account the redundant capability of the electrical power distribution subsystems, and other indications available in the Control Room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR

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Table B 3.8.10-1 (page 1 of 1)

AC and DC Electrical Power Distribution Systems

1	4160 Volt Emergency Bus
1	480 Volt Emergency Bus
2	120 Volt AC Vital Busses
2	125 Volt DC Busses
2	125 Volt Battery Banks (one of which may be the reserve battery) (one associated battery charger per battery bank supplying the required DC busses)

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of irradiated fuel assemblies within the Containment Structure, a release of fission product radioactivity within the Containment Structure will be restricted from escaping to the environment when the LCO requirements are met. In MODEs 1, 2, 3, and 4, this is accomplished by maintaining Containment OPERABLE, as described in LCO 3.6.1. In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment atmosphere from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no design basis accident potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The Containment Structure serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR Part 100. Additionally, the Containment Structure provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of the Containment Structure. During CORE ALTERATIONS or movement of irradiated fuel assemblies within Containment, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODEs 1, 2, 3, and 4 operation in accordance with LCO 3.6.2. Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when Containment OPERABILITY is required.

In other situations, the potential for containment pressurization as a result of an accident is not present, therefore, less stringent requirements are needed to isolate the containment atmosphere from the outside atmosphere. Both containment personnel air lock doors may be open during the movement of irradiated fuel assemblies in containment and during CORE ALTERATIONS; provided one air lock door is OPERABLE, the plant is in MODE 6 with at least 23 ft of water above the fuel, and a designated individual is continuously available to close the air lock door. This individual must be stationed at the Auxiliary Building side of the outer air lock door. OPERABILITY of a containment personnel air lock door requires that the door is capable of being closed, that the door is unblocked, and no cables or hoses are run through the air lock. During CORE ALTERATIONS or movement of irradiated fuel assemblies in containment, the requirement for at least 23 ft of water above the fuel, ensures that there is sufficient time to close the personnel air lock following a loss of SDC before boiling occurs and minimizes activity release after a fuel handling accident. (The water level requirement needs to be stated in this Specification to address an exemption to CORE ALTERATIONS in the Applicability of LCO 3.9.6 regarding control element assembly drive shaft coupling and uncoupling.)

The requirements on containment penetration closure, ensure that a release of fission product radioactivity within the Containment Structure will be restricted to within regulatory limits.

The Containment Purge Valve Isolation System, for the purposes of compliance with LCO 3.9.3, item d.2, includes a 48 inch purge penetration and a 48 inch exhaust penetration. For the purposes of compliance with LCO 3.9.3, the containment vent isolation valves are not considered part of the Containment Purge Valve Isolation System since they may not be capable of being closed automatically. The containment vent, includes a four inch purge penetration and a four inch exhaust penetration. During MODEs 1, 2, 3, and 4, the normal purge and exhaust penetrations are isolated (via a blind flange, if installed or by the purge valves). The containment vent valves can be opened intermittently, but are closed automatically by the Engineered Safety Features Actuation System. Neither of the subsystems is subject to a Specification in MODE 5.

In MODE 6, large air exchanges are desired to conduct refueling operations. The normal 48 inch purge system is used for this purpose and all valves are closed by the Engineered Safety Features Actuation System in accordance with LCO 3.3.7.

The containment vent isolation valves are required to be closed during CORE ALTERATIONS or movement of irradiated fuel within Containment. These valves are connected to the penetration room Technical Specification emergency air cleanup systems, which exhaust to the outside atmosphere through high efficiency particulate air and charcoal filters.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved in accordance with appropriate American Society of Mechanical Engineers / American National Standards Institute Codes, and may include use of a material that can provide a temporary ventilation barrier for the other containment penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within the Containment Structure, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Reference 1). The fuel handling accident, described in Reference 1, includes dropping a single irradiated fuel assembly which would then rotate to a horizontal position, strike a protruding structure, and rupture the fuel pins. The requirements of LCO 3.9.6, and the minimum decay time of 100 hours prior to CORE ALTERATIONS, ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are within the acceptance limits given in Reference 1.

Containment penetrations satisfy 10 CFR 50.36(c)(2)(ii), Criterion 3.

LCO

This LCO limits the consequences of a fuel handling accident in Containment Structure, by limiting the potential escape paths for fission product radioactivity released within Containment. The LCO requires any penetration providing direct access from the Containment Structure atmosphere to the outside atmosphere (including the containment vent isolation valves) to be closed, except for the OPERABLE containment purge and exhaust penetrations and the containment personnel air locks. For the OPERABLE containment purge and exhaust penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge Valve Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic purge and exhaust valve closure times specified in the UFSAR can be achieved, and therefore meet the assumptions used in the safety analysis to ensure releases through the valves are terminated, such that the radiological doses are within the acceptance limit.

Both containment personnel air lock doors may be open under administrative controls during movement of irradiated fuel in Containment and during CORE ALTERATIONS provided that one OPERABLE door is capable of being closed in the event of a fuel handling accident. Note that the 23 ft referred to in the LCO of the Technical Specification is a minimum water level, and water levels greater than 23 ft are acceptable and conservative. The administrative controls consist of a designated individual available immediately outside the personnel air lock to close an OPERABLE air lock door. Should a fuel handling accident occur inside the Containment Structure, one personnel air lock door will be closed following an evacuation of the Containment Structure.

The LCO is modified by a Note which allows the emergency air lock temporary closure device to replace an emergency air lock door. The temporary closure device provides an

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adequate barrier to shield the environment from the containment atmosphere in case of a design basis event.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within the Containment Structure because this is when there is a potential for a fuel handling accident. In MODEs 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODEs 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within the Containment Structure are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

With the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere not in the required status, (including the Containment Purge and Exhaust Isolation System not capable of automatic actuation when the purge and exhaust valves are open) the unit must be placed in a condition in which the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within the Containment Structure. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This SR demonstrates that each of the containment penetrations required to be in its closed position, is in that position. The surveillance test on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also, the surveillance test will demonstrate that each purge and exhaust valve operator has motive power, which will ensure each valve is capable of being closed by an OPERABLE automatic Containment Purge Valve Isolation System.

The surveillance test is performed every seven days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the Containment Structure. The surveillance test interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. A surveillance test before the start of refueling operations will provide two or three verifications during the applicable period for this LCO. As such, this SR ensures that a postulated fuel handling accident, that releases fission product radioactivity within the Containment Structure, will not result in a release of fission product radioactivity to the environment in excess of those described in Reference 1.

SR 3.9.3.2

This SR demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The once each refueling outage Frequency, maintains consistency with other similar Engineered Safety Features Actuation System instrumentation and valve testing requirements. However, in order to ensure the SR Frequency is satisfied, this surveillance test is typically performed once per refueling outage prior to the start of CORE ALTERATIONS or movement of irradiated fuel assemblies within Containment. In LCO 3.3.7, the Containment Radiation Signal System requires a CHANNEL CHECK every 12 hours and a CHANNEL FUNCTIONAL TEST every 92 days to ensure the channel OPERABILITY during refueling operations. Every 24 months a CHANNEL CALIBRATION is performed. The system actuation response time is demonstrated every 24 months during refueling on a STAGGERED TEST BASIS. Surveillance Requirement 3.6.3.4 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These surveillance tests performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the Containment Structure.

REFERENCES

1. UFSAR, Section 14.18, "Fuel Handling Incident"