DESIGN CONTROL DOCUMENT FOR THE US-APWR

Chapter 16
Technical Specifications

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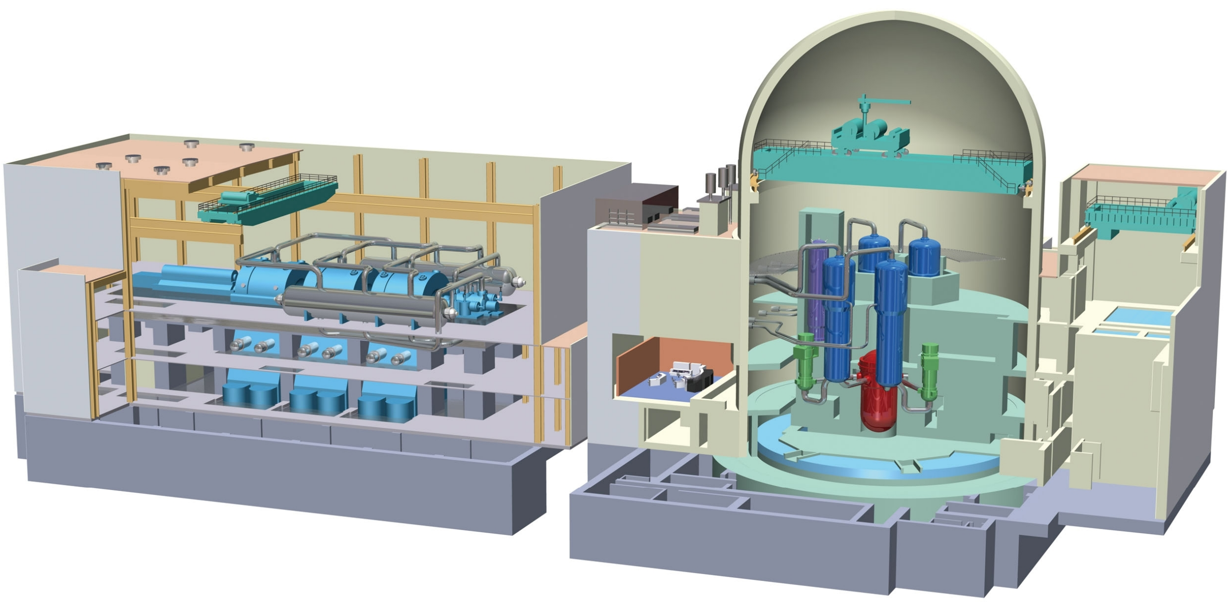

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16.0 TECHNICAL SPECIFICATIONS

16.1 Technical Specifications

16.1.1 Introduction to Technical Specifications

16.1.1.1 Technical Specifications Derivation Criteria

The US-APWR Technical Specifications include the following categories of information as required by 10 CFR 50.36 (Ref. 16.1-1) and 10 CFR 50.36a (Ref. 16.1-2) for operating reactors:

- safety limits
- limiting safety system settings
- LCOs (and associated remedial actions, if any)
- surveillance requirements
- design features
- administrative controls (including requirements on effluents containing radioactive material)

The identification of the structures, systems, components, and parameters for which Limiting Conditions for Operation (LCOs) have been included in the US-APWR Technical Specifications was based on the screening criteria of 10 CFR 50.36(c)(2)(ii) as stated below:

- Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.
- A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analyses that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
- A structure, system or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
- A structures, system, and component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

16.1.1.2 Technical Specification Content

The US-APWR Technical Specifications content meets the 10 CFR 50.36 requirements. NUREG 1431, Rev. 3.1, (Ref. 16.1-3) was selected as the most appropriate guidance for developing the US-APWR Technical Specifications for consistency with the Technical Specification Improvement Program. The US-APWR Technical Specifications differ from NUREG 1431 only as necessary to reflect technical differences between the Westinghouse Owner’s Group Standard Technical Specifications design and the US-APWR design.

1. Completion Time and Surveillance Frequencies

Where possible, the Completion Times and Surveillance Frequencies specified in NUREG 1431 have been applied to similar Actions and Surveillance Requirements in US-APWR. For US-APWR system design differences which lead to deviations from NUREG 1431 Completion Times and Surveillance Frequencies or for those US-APWR Technical Specifications for which no comparable NUREG 1431 system/function exists, refer to Chapter 19 for a discussion regarding selection of Completion Times and Surveillance Frequencies.

2. Plant Design Differences

There are some differences between the US-APWR plant design and current designs in NUREG 1431. Differences include, but are not limited to, the four train design, digital instrumentation, and gas turbine generators.

3. LCO and Bases [TBD] information

Preliminary information or the acronym “TBD” (to be determined) enclosed in brackets [ ] are used for information that is required for completion of the Technical Specifications, but not available due to: (1) the detailed design, equipment selection, or other efforts are not sufficiently complete, or (2) for information that will not be available until a plant is constructed, such as information established by startup testing.

4. Combined License Information

The US-APWR Technical Specifications are intended to be used as a guide in the development of the plant-specific Technical Specifications by a Combined License (COL) Applicant. The bracketed preliminary information will be replaced with plant specific values in plant specific technical specifications.

5. The modification based on TSTF

The US-APWR Technical Specifications include the modification based on TSTF-425, Rev. 3 (Ref. 16.1-4), TSTF-427, Rev.2 (Ref.16.1-5), TSTF-448, Rev. 3 (Ref. 16.1-6), TSTF-490, Rev. 0 (Ref. 16.1-7) and TSTF-511, Rev.0 (Ref. 16.1-8).

6. Risk-Informed Technical Specifications

The US-APWR Technical Specifications provide the framework for Risk-Managed Technical Specifications (RMTS) and Surveillance Frequency Control Program (SFCP), which have been developed under the Risk-Informed Technical Specifications Initiative 4b and 5b. The guidelines for these initiatives were prepared by NEI and have been approved by the NRC. The approved guidance for RMTS is NEI 06-09 (Revision 0) (Ref. 16.1-9). The Risk-Informed Completion Times are applied to as many systems as seemed reasonable, particularly the four-train safety systems, to maximize the operational flexibility for the plant operators. NEI 04-10 (Revision 1) (Ref. 16.1-10) provides the risk-informed method for licensee control of Surveillance Frequencies. TSTF-425 (Revision 3) (Ref. 16.1-4) relocates the majority of the Technical Specification Surveillance Requirement Frequencies to the licensee-controlled program. The administrative control specifies the requirements for SFCP.

There are several requirements to implement RMTS and SFCP specified by NEI 06-09 and NEI 04-10. The technical adequacy of the PRA model to be utilized in RMTS is one of the most important things among these requirements. For the US-APWR, Chapter 19 of this design control document and the associated technical report provide the PRA model which essentially satisfy the NEI guidance requirement. However, in order to strictly meet the NEI requirement, the PRA model should be plant-specific which incorporate as-built information. Therefore, RMTS cannot be fully implemented until this necessary information is available.

In addition, the following subjects are the NEI 06-09 requirements that cannot be completed at the application stage of the design certification or COL due to lack of plant-specific or station-specific information as well as the PRA model. (The requirement for the PRA model is included in the following list for completeness.)

- Establishment of the station procedure of the Configuration Risk Management Program (CRMP) process with specifying the station functional organizations and personnel responsible for each action of CRMP implementation,
- Training of responsible personnel,
- Preparation of a PRA model to meet the technical adequacy requirement of NEI 06-09,
- Preparation of an appropriate CRM tool.

The COL Applicant who chooses to implement RMTS needs to establish the CRMP including the above mentioned subjects. This program assures the implementation of the plant-specific RMTS before the actual plant operation as indicated in Section 5.5.18 “Configuration Risk Management Program” of the US-APWR Technical Specifications. The establishment of the CRMP is a requirement of Technical Specifications of the COLA which adopts RMTS and shall be completed, and reviewed and approved by NRC prior to the initial fuel loading.

Similarly, the requirements of NEI 04-10 also cannot be completed at the application stage of the design certification or COL due to lack of plant-specific or station-specific information.

The Surveillance Requirements themselves will remain in the Technical Specifications, pursuant to 10 CFR 50.36 (Ref. 16.1-1). The administrative controls section of the Technical Specifications specifies the requirements for SFCP and the COL Applicant who chooses to implement SFCP needs to establish this program to control Surveillance Frequencies and make future changes to the Surveillance Requirement Frequencies.

A multi-disciplinary plant decision-making panel is utilized to evaluate determinations of revised Surveillance Frequencies, based on operating experience, test history, manufacturer’s recommendations, codes and standards, and other factors, in conjunction with the risk insights from the PRA. Results and bases for the decision must be documented.

The establishment of the SFCP is a requirement of Technical Specifications of the COLA which adopts this program and shall be completed, and reviewed and approved by NRC prior to the initial fuel loading.

16.1.2 References

16.1-1 General Design Criteria for Nuclear Power Plants, NRC Regulations Title 10, Code of Federal Regulations, 10 CFR Part 50.36, “Technical specifications”.

16.1-2 General Design Criteria for Nuclear Power Plants, NRC Regulations Title 10, Code of Federal Regulations, 10 CFR 50.36a, “Technical specifications on effluents from nuclear power reactors”.

16.1-3 U.S. Nuclear Regulatory Commission, NUREG 1431, Rev. 3.1 December, 2005, “Standard Technical Specifications Westinghouse Plants”.

16.1-4 Technical Specification Task Force, TSTF-425, Rev. 3, “Relocate Surveillance Frequencies to Licensee Control”.

16.1-5 Technical Specification Task Force, TSTF-427, Rev.2, “Allowance for Non Technical Specification Barrier Degradation on Support System OPERABILITY”.

16.1-6 Technical Specification Task Force, TSTF-448, Rev. 3, “Control Room Habitability”.

16.1-7 Technical Specification Task Force, TSTF-490, Rev. 0, “Deletion of E Bar definition and revision to RCS specific activity”.

16.1-8 Technical Specification Task Force, TSTF-511, Rev.0, “Eliminate Working Hour Restrictions from TS5.2.2 to Support Compliance with 10 CFR Part 26”.

16.1-9 Nuclear Energy Institute, NEI 06-09 (Revision 0), “Risk-Managed Technical Specifications (RMTS) Guidelines” issued in November 2006.

16.1-10 Nuclear Energy Institute, NEI 04-10 (Revision 1), “Risk-Informed Method for Control of Surveillance Frequencies” issued in April 2007.

US-APWR
Technical Specifications

Specifications

1.0 USE AND APPLICATION

1.1 Definitions

--NOTE--
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST which is applied to analog equipment shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state required for OPERABILITY of a logic circuit and the verification of the required logic output, including Time Delays. The ACTUATION LOGIC TEST as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.

CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of channel measurement devices such that the channel responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY. This shall include the processing of the signal within the digital controller to which the channel measurement device is directly interfaced (i.e., RPS, ESFAS or SLS.) CHANNEL CALIBRATION encompasses devices that are subject to drift between surveillance intervals and all input devices that are not tested through continuous automatic self-testing. Refer to TADOT for output devices that are not tested through continuous automatic self-testing. The performance of a CHANNEL CALIBRATION shall be consistent with Specification 5.5.21 “Setpoint Control Program” (SCP). CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital Visual Display Unit (VDU) readout. The digital value read on the VDU originates in the controller that processes the trip, actuation, interlock or safety-related display Functions, and is the same digital value processed for those Functions. The CHANNEL CALIBRATION overlaps with other surveillance requirements to adequately test the PSMS safety Functions. For analog measurements, CHANNEL CALIBRATION confirms the channel accuracy at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range.

1.1 Definitions

CHANNEL CALIBRATION (continued)	For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel's state change at the required setpoint. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter. A CHANNEL CHECK may be conducted manually or automatically. Either method may be used to satisfy the surveillance frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria are not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum surveillance frequency.

1.1 Definitions

CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel at a point that overlaps with the signal checked during CHANNEL CALIBRATION to verify OPERABILITY of all remaining devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY such that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping, or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit-specific document that provides cycle-specific parameter limits. These cycle-specific parameter limits shall be determined for each cycle in accordance with Specification 5.6.3. Plant operation within these limits is addressed in individual Specifications.

1.1 Definitions

DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same committed effective dose equivalent as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The dose conversion factors used for this calculation shall be those listed in Table 2.1 of EPA Federal Guidance Report No. 11, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion,” EPA-520/1-88-020, September 1988.
DOSE EQUIVALENT XE-133	DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same effective dose equivalent as the quantity and isotopic mixture of noble gases (Kr-85m, Kr-85, Kr-87, Kr-88, Xe-133,- and Xe-135) actually present. The dose conversion factors used for this calculation shall be those listed in Table III.1 of EPA Federal Guidance Report No. 12, “External Exposure to Radionuclides in Air, Water, and Soil,“ EPA 402-R-93-081, September 1993.
ENGINEERED SAFETY FEATURES (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include Class 1E GTG starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC. The ESF RESPONSE TIME includes post-test maintenance as necessary, based on manufacturer’s recommendation, to maintain device reliability.

1.1 Definitions

LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank,

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE, or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE);

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE, and

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MEMORY INTEGRITY CHECK (MIC)

A MEMORY INTEGRITY CHECK (MIC) is a check of the PSMS software memory integrity to ensure there is no change to the internal PSMS software that would impact its functional operation, including digital Nominal Trip Setpoint values, Time Constants, Time Delays or the continuous automatic self-test function. The MIC overlaps with other surveillance requirements to adequately test the PSMS safety functions.

The PSMS is automatically self-tested on a continuous basis from the digital side of all input modules to the digital side of all output modules. Continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. For the PSMS the continuous automatic self-testing is described in “Safety I&C System Description and Design Process, “MUAP-07004 Section 4.3 and “Safety System

1.1 Definitions

	Digital Platform -MELTAC-, “MUAP-07005 Section 4.1.5. The software memory integrity test is described in “Safety I&C System Description and Design Process, “MUAP-07004 Section 4.4.1 and “Safety System Digital Platform -MELTAC-, “MUAP-07005 Section 4.1.4.1.c.
MODE	A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE – OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, Initial Test Program, b. Authorized under the provisions of 10 CFR 50.59, or c. Otherwise approved by the Nuclear Regulatory Commission.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates and the low temperature overpressure protection arming temperature, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.4.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 4451 MWt.

1.1 Definitions

REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC. The RTS RESPONSE TIME includes post-test maintenance as necessary, based on manufacturer's recommendation, to maintain device reliability.
SAFETY VDU TEST	A SAFETY VDU TEST is a check of the touch response and display OPERABILITY of the Safety VDU (S-VDU). Safety VDU touch screens are tested by manually touching screen targets and confirming correct safety VDU response. The SAFETY VDU TEST overlaps with the MIC for the Safety VDU processor, to ensure the S-VDU is OPERABLE. The SAFETY VDU TEST is explained in "Safety I&C System Description and Design Process," MUAP-07004 Section 4.4.1.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. However, with all RCCAs verified fully inserted by two independent means, it is not necessary to account for a stuck RCCA in the SDM calculation. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM, and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.

1.1 Definitions

STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.1 Definitions

TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of all devices in the channel required for trip actuating device OPERABILITY. The TADOT may be performed by means of any series of sequential, overlapping, or total channel steps. There are two types of binary devices - those that have no drift potential, such as Manual Initiation switches and Actuation Outputs, and those that have drift potential, such as undervoltage (UV) relays, valve position limit switches and RTB trip devices. The OPERABILITY of binary devices that have drift potential is confirmed through CHANNEL CALIBRATION and/or RESPONSE TIME testing. For some binary devices subject to drift potential, a TADOT may be specified in addition to these surveillance requirements. The OPERABILITY of binary devices that have no drift potential is confirmed only through TADOT. For devices with drift potential, the CHANNEL CALIBRATION confirms the accuracy of the device's binary state change with regard to its trip setpoint requirement (i.e., the Allowable Value). The RESPONSE TIME test confirms the accuracy of the devices state change with regard to its trip timing requirement. The TADOT confirms only the state change OPERABILITY (i.e., there is no setpoint or timing accuracy confirmation needed). The TADOT also includes maintenance as necessary, based on manufacturer's recommendation, to maintain device reliability. For some binary devices with drift potential, a TADOT is specified in addition to the CHANNEL CALIBRATION and/or RESPONSE TIME test. The TADOT is specified on a more frequent basis than the CHANNEL CALIBRATION or RESPONSE TIME test, to confirm the state change OPERABILITY of the devices, without checking its state change setpoint or timing accuracy. Checking the setpoint or timing accuracy more frequently than the CHANNEL CALIBRATION or RESPONSE TIME test interval is unnecessary, because the total channel uncertainty, including setpoint and/or timing drift between test intervals, is included in determination of the Nominal Setpoint, the Allowable Value and the response time requirement.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[(a)]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown[(b)]	< 0.99	NA	$350 > T_{avg} > 200$
5	Cold Shutdown[(b)]	< 0.99	NA	≤ 200
6	Refueling[(c)]	NA	NA	NA

(a) Excluding decay heat.

(b) All reactor vessel head closure bolts fully tensioned.

(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are <u>AND</u> and <u>OR</u>. The physical arrangement of these connectors constitutes logical conventions with specific meanings.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.
EXAMPLES	The following examples illustrate the use of logical connectors.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a subsequent train, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the first inoperability and

1.3 Completion Times

DESCRIPTION (continued)

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ."

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

1.3 Completion Times

EXAMPLES (continued)

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Conditions A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

1.3 Completion Times

EXAMPLES (continued)

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable pump. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

Upon restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for > 7 days.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

EXAMPLES (continued)

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A.

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

EXAMPLES (continued)

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (including the extension) expires while one or more valves are still inoperable, Condition B is entered.

EXAMPLE 1.3-5

ACTIONS

-- NOTE --

Separate Condition entry is allowed for each inoperable valve.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

1.3 Completion Times

EXAMPLES (continued)

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

1.3 Completion Times

EXAMPLES (continued)

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be completed within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated. AND A.2 Restore subsystem to OPERABLE status.	1 hour AND Once per 8 hours thereafter 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

1.3 Completion Times

EXAMPLES (continued)

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

[EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required component inoperable.	A.1 Restore required component to OPERABLE status. OR A.2 Apply the requirements of Specifications 5.5.18	72 hours 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

1.3 Completion Times

EXAMPLES (continued)

This example shows the option to apply Risk-Informed Completion Time (RICT). When Condition A is entered, either Required Action A.1 or A.2 shall be taken within 72 hours.

When taking Required Action A.2, whether the plant configuration is acceptable beyond Completion Time (72 hours in this example) is evaluated from the viewpoint of plant risk. If it is not acceptable, Required Action A.2 cannot be taken and the only possible option is to take Required Action A.1. If it is acceptable, the RICT is calculated in accordance with the Configuration Risk Management Program (CRMP) specified in Administrative Control Section 5.5.18 and the new Completion Time is set to RICT or 30 days whichever is less.

If a required component is not restored within the new Completion Time, Condition B is entered.

If an other component becomes inoperable while taking Required Action A.2, the plant risk might be affected. Hence, RICT shall be recalculated within 12 hours from the plant configuration change. The details are specified in CRMP.]

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, The Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0.2, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria.

Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

1.4 Frequency

DESCRIPTION (continued)

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered, or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed, or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discuss these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLES (continued)

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The Surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the MODE or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

EXAMPLES (continued)

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------------------NOTE--------------------------- Not required to be performed until 12 hours after ≥ 25% RTP. ---	
Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------------------NOTE--------------------------- Only required to be met in MODE 1. --- Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

EXAMPLES (continued)

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------------------NOTE--------------------------- Only required to be performed in MODE 1. ---	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------------------NOTE--------------------------- Not required to be met in MODE 3. ---	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

2.0 SAFETY LIMITS (SLS)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the limits specified in the COLR; and the following SLs shall not be exceeded:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained
$\geq$ 1.35 for typical hot channel
$\geq$ 1.33 for thimble hot channel
with WRB-2 DNB correlation and revised thermal design procedure (RTDP) .

2.1.1.2 The peak fuel centerline temperature shall be maintained < 5072°F, decreasing by 58°F per 10,000 MWD/MTU of burnup.

2.1.2 Reactor Coolant System (RCS) Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained $\leq$ 2733.5 psig.

2.2 SAFETY LIMIT VIOLATIONS

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1

LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2, LCO 3.0.7, LCO 3.0.8, and LCO 3.0.9.

LCO 3.0.2

Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required unless otherwise stated.

LCO 3.0.3

When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours,

b. MODE 4 within 13 hours, and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4

When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time;

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications, or

3.0 LCO Applicability

LCO 3.0.4 (continued)

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

LCO 3.0.5 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

LCO 3.0.6 When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.15, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

LCO 3.0.7 Test Exception LCOs 3.1.8 and 3.1.9 allow specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 LCO Applicability

LCO 3.0.8

When one or more required snubbers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if risk is assessed and managed, and:

a. the snubbers not able to perform their associated support function(s) are associated with only one train or subsystem of a multiple train or subsystem supported system or are associated with a single train or subsystem supported system and are able to perform their associated support function within 72 hours; or

b. the snubbers not able to perform their associated support function(s) are associated with more than one train or subsystem of a multiple train or subsystem supported system and are able to perform their associated support function within 12 hours.

At the end of the specified period the required snubbers must be able to perform their associated support function(s), or the affected supported system LCO(s) shall be declared not met.

LCO 3.0.9

When one or more required barriers are unable to perform their related support function(s), any supported system LCO(s) are not required to be declared not met solely for this reason for up to 30 days provided that at least one train or subsystem of the supported system is OPERABLE and supported by barriers capable of providing their related support function(s), and risk is assessed and managed. This specification may be concurrently applied to more than one train or subsystem of a multiple train or subsystem supported system provided at least one train or subsystem of the supported system is OPERABLE and the barriers supporting each of these trains or subsystems provide their related support function(s) for different categories of initiating events.

If the required OPERABLE train or subsystem becomes inoperable while this specification is in use, it must be restored to OPERABLE status within 24 hours or the provisions of this specification cannot be applied to the trains or subsystems supported by the barriers that cannot perform their related support function(s).

At the end of the specified period, the required barriers must be able to perform their related support function(s) or the supported system LCO(s) shall be declared not met.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1	SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance for the required equipment, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance for the required equipment within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.
SR 3.0.2	The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met. For Frequencies specified as "once," the above interval extension does not apply. If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance. Exceptions to this Specification are stated in the individual Specifications.
SR 3.0.3	If it is discovered that a Surveillance was not performed within its specified Frequency for the required equipment, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed. If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

3.0 SR Applicability

SR 3.0.4

Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency for the required equipment, except as provided by SR 3.0.3. When an LCO is not met, due to Surveillances not having been met for the required equipment, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits specified in the COLR.

APPLICABILITY: MODE 2 with $k_{eff} < 1.0$,
MODES 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limits.	A.1 Initiate boration to restore SDM to within limits.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within the limits specified in the COLR.	[24 hours OR In accordance with the Surveillance Frequency Control Program]

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ± 1% Δk/k of predicted values.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Measured core reactivity not within limit.	A.1 Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	7 days
	<u>AND</u>	
	A.2 Establish appropriate operating restrictions and SRs.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.2.1	---------------------------NOTE------------------------------ The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. --- Verify measured core reactivity is within ± 1% $\Delta k/k$ of predicted values.	Once prior to entering MODE 1 after each refueling AND --------NOTE-------- Only required after 60 EFPD ------------------------ [31 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit,
MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MTC not within upper limit.	A.1 Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC is within upper limit.	Prior to entering MODE 1 after each refueling

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.3.2	---------------------------NOTES--------------------------- 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --- Verify MTC is within lower limit.	Once each cycle

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE.

AND

Individual indicated rod positions shall be within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Be in MODE 3.	6 hours
B. One rod not within alignment limits.	B.1 Restore rod to within alignment limits.	1 hour
	OR	
	B.2.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	OR	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.2.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	B.2.2 Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	<u>AND</u>	
	B.2.3 Verify SDM is within the limits specified in the COLR.	Once per 12 hours
	<u>AND</u>	
	B.2.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	72 hours
	<u>AND</u>	
	B.2.5 Perform SR 3.2.2.1.	72 hours
	<u>AND</u>	
	B.2.6 Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	D.1.2 Initiate boration to restore required SDM to within limit. <u>AND</u> D.2 Be in MODE 3.	1 hour 6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 3.15 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. T_{avg} ≥ 500°F and b. All reactor coolant pumps operating.	Prior to criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each shutdown bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODES 1 and 2.

---NOTE---
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM is within the limits specified in the COLR. <u>OR</u> A.1.2 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Restore shutdown banks to within limits.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the insertion limits specified in the COLR.	[12 hours OR In accordance with the Surveillance Frequency Control Program

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥1.0.

--NOTE--
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank insertion limits not met.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Restore control bank(s) to within limits.	2 hours
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	OR	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	B.2 Restore control bank sequence and overlap to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2 with k_{eff} < 1.0.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the insertion limits specified in the COLR.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.1.6.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Rod Position Indication (RPI) System and the Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators indirectly by using movable incore detectors.	Once per 8 hours
	OR	
	A.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
B. More than one RPI per group inoperable.	B.1 Place the control rods under manual control.	Immediately
	AND	
	B.2 Monitor and record Reactor Coolant System T_{avg}.	Once per 1 hour
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.3 Verify the position of the rods with inoperable position indicators indirectly by using the movable incore detectors.	Once per 8 hours
	<u>AND</u>	
	B.4 Restore inoperable position indicators to OPERABLE status such that a maximum of one RPI per group is inoperable.	24 hours
C. One or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	C.1 Verify the position of the rods with inoperable position indicators indirectly by using movable incore detectors.	4 hours
	<u>OR</u>	
	C.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
D. One demand position indicator per bank inoperable for one or more banks.	D.1.1 Verify by administrative means all RPIs for the affected banks are OPERABLE.	Once per 8 hours
	<u>AND</u>	
	D.1.2 Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart.	Once per 8 hours
	<u>OR</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	D.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify each RPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	Once prior to criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions – MODE 1

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of:

LCO 3.1.4, "Rod Group Alignment Limits,"
LCO 3.1.5, "Shutdown Bank Insertion Limits,"
LCO 3.1.6, "Control Bank Insertion Limits,"
LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and
LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)"

may be suspended provided:

a. THERMAL POWER is maintained $\leq$ 85% RTP;

b. Power Range Neutron Flux – High trip setpoints are $\leq$ 10% RTP above the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP; and

c. SDM is within the limits specified in the COLR.

APPLICABILITY: MODE 1 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. AND A.2 Suspend PHYSICS TESTS exceptions.	15 minutes 1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. THERMAL POWER not within limit.	B.1 Reduce THERMAL POWER to within limit. <u>OR</u> B. 2 Suspend PHYSICS TESTS exceptions.	1 hour 1 hour
C. Power Range Neutron Flux-High trip setpoints > 10% RTP above the PHYSICS TEST power level. <u>OR</u> Power Range Neutron Flux-High trip setpoints > 90% RTP.	C.1 Restore Power Range Neutron Flux-High trip setpoints to ≤ 10% above the PHYSICS TEST power level, or to ≤ 90% RTP, whichever is lower. <u>OR</u> C.2 Suspend PHYSICS TESTS exceptions.	1 hour 1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Verify THERMAL POWER is ≤ 85% RTP.	1 hour
SR 3.1.8.2	Verify Power Range Neutron Flux – High trip setpoints are ≤ 10% above the PHYSICS TEST power level, and ≤ 90% RTP.	Within 8 hours prior to initiation of PHYSICS TESTS
SR 3.1.8.3	Perform SR 3.2.1.1 and SR 3.2.2.1.	12 hours
SR 3.1.8.4	Verify SDM is within the limits specified in the COLR.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.9 PHYSICS TESTS Exceptions – MODE 2

LCO 3.1.9 During the performance of PHYSICS TESTS, the requirements of:

LCO 3.1.3, "Moderator Temperature Coefficient,"
LCO 3.1.4, "Rod Group Alignment Limits,"
LCO 3.1.5, "Shutdown Bank Insertion Limits,"
LCO 3.1.6, "Control Bank Insertion Limits," and
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3 and 15.c, may be reduced to 3 required channels, provided:

a. RCS lowest loop average temperature is ≥ 541°F,

b. SDM is within the limits specified in the COLR, and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY: During PHYSICS TESTS initiated in MODE 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Suspend PHYSICS TESTS exceptions.	15 minutes 1 hour
B. THERMAL POWER not within limit.	B.1 Open reactor trip breakers.	Immediately
C. RCS lowest loop average temperature not within limit.	C.1 Restore RCS lowest loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.9.1	Perform CHANNEL CALIBRATION on power range and intermediate range channels per SR 3.3.1.9 consistent with Specification 5.5.21, Setpoint Control Program (SCP).	Prior to initiation of PHYSICS TESTS
SR 3.1.9.2	Verify the RCS lowest loop average temperature is ≥ 541°F.	[30 minutes OR In accordance with the Surveillance Frequency Control Program]
SR 3.1.9.3	Verify THERMAL POWER is ≤ 5% RTP.	[30 minutes OR In accordance with the Surveillance Frequency Control Program]
SR 3.1.9.4	Verify SDM is within the limits specified in the COLR.	[24 hours OR In accordance with the Surveillance Frequency Control Program]

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (CAOC-W(Z) Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
---------------NOTE------------- Required Action A.4 shall be completed whenever this Condition is entered. --------------------------------------	A.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit.	15 minutes after each $F_Q^C(Z)$ determination
	AND	
A. $F_Q^C(Z)$ not within limit.	A.2 Reduce Power Range Neutron Flux - High trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	
	A.3 Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	
	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
---------------NOTE------------- Required Action B.4 shall be completed whenever this Condition is entered. --------------------------------------	B.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	<u>AND</u>	
B. $F_Q^W(Z)$ not within limits.	B.2 Reduce Power Range Neutron Flux - High trip setpoints ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	72 hours
	<u>AND</u>	
	B.3 Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	72 hours
	<u>AND</u>	
	B.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action B.1
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

During power escalation at the beginning of each cycle, THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q^C(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> [31 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	-------------------------------NOTE------------------------------ If measurements indicate that the maximum $F_Q^C(Z)$ has increased since the previous evaluation of $F_Q^C(Z)$: a. Increase $F_Q^W(Z)$ by a factor specified in the COLR and reverify $F_Q^W(Z)$ is within limits or b. Repeat SR 3.2.1.2 once per 7 EFPD until either a. above is met or two successive flux maps indicate that the maximum $F_Q^C(Z)$ has not increased. ---	
	Verify $F_Q^W(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^W(Z)$ was last verified <u>AND</u> [31 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F_{\Delta H}^{N}$)

LCO 3.2.2 $F_{\Delta H}^{N}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----------NOTE----------- Required Actions A.2 and A.3 must be completed whenever Condition A is entered. ------------------------------- $F_{\Delta H}^{N}$ not within limit.	A.1.1 Restore $F_{\Delta H}^{N}$ to within limit.	4 hours
	<u>OR</u>	
	A.1.2.1 Reduce THERMAL POWER to < 50% RTP.	4 hours
	<u>AND</u>	
	A.1.2.2 Reduce Power Range Neutron Flux - High trip setpoints to ≤ 55% RTP.	72 hours
	<u>AND</u>	
	A.2 Perform SR 3.2.2.1.	24 hours
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.3 --------------NOTE-------------- THERMAL POWER does not have to be reduced to comply with this Required Action. ------------------------------------- Perform SR 3.2.2.1.	 Prior to THERMAL POWER exceeding 50% RTP <u>AND</u> Prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> [31 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

LCO 3.2.3 The AFD:

a. Shall be maintained within the target band about the target flux difference. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

---NOTES---

1. The AFD shall be considered outside the target band when two or more OPERABLE excore channels indicate AFD to be outside the target band.

2. With THERMAL POWER ≥ 50% RTP, penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

3. With THERMAL POWER < 50% RTP and > 15 % RTP, penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6, provided AFD is maintained within acceptable operation limits.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. THERMAL POWER ≥ 90% RTP. AND AFD not within the target band.	A.1 Restore AFD to within target band.	15 minutes
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER to < 90% RTP.	15 minutes
C. ------------NOTE---------- Required Action C.1 must be completed whenever Condition C is entered. ------------------------------- THERMAL POWER < 90% and ≥ 50% RTP with cumulative penalty deviation time > 1 hour during the previous 24 hours. OR THERMAL POWER < 90% and ≥ 50% RTP with AFD not within the acceptable operation limits.	C.1 Reduce THERMAL POWER to < 50% RTP.	30 minutes
D. Required Action and associated Completion Time for Condition C not met.	D.1 Reduce THERMAL POWER to < 15% RTP.	9 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD is within limits for each OPERABLE excore channel.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.2.3.2	Update target flux difference.	Once within 31 EFPD after each refueling <u>AND</u> [31 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.3.3	-------------------------------NOTE----------------------------- The initial target flux difference after each refueling may be determined from design predictions. -- Determine, by measurement, the target flux difference.	Once within 31 EFPD after each refueling AND [92 EFPD thereafter OR In accordance with the Surveillance Frequency Control Program]

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. QPTR not within limit.	A.1 Reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR > 1.00.	2 hours after each QPTR determination
	AND	
	A.2 Perform SR 3.2.4.1	Once per 12 hours
	AND	
	A.3 Perform SR 3.2.1.1, SR 3.2.1.2, and SR 3.2.2.1.	24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 AND Once per 7 days thereafter
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.4 Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.5 -------------NOTES------------- 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. ------------------------------------- Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.6 ---------------NOTE-------------- Perform Required Action A.6 only after Required Action A.5 is completed. ------------------------------------- Perform SR 3.2.1.1, SR 3.2.1.2, and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Action A.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.4.1	------------------------------NOTES------------------------- 1. With input from one Power Range Neutron Flux channel inoperable and THERMAL POWER ≤ 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. --- Verify QPTR is within limit by calculation.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.2.4.2	------------------------------NOTE------------------------- Not required to be performed until 12 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER > 75% RTP. --- Verify QPTR is within limit using the movable incore detectors.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One required Manual Reactor Trip Function inoperable.	B.1 Restore train to OPERABLE status.	72 hours
	<u>OR</u>	
	B.2 Be in MODE 3.	78 hours
C. One required Manual Reactor Trip Function inoperable.	C.1 Restore train to OPERABLE status.	72 hours
	<u>OR</u>	
	C.2.1 Initiate action to fully insert all rods.	72 hours
	<u>AND</u>	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	73 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required train inoperable.	D.1 Restore train to OPERABLE status.	48 hours
	OR	
	D.2.1 Initiate action to fully insert all rods.	48 hours
	AND	
	D.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One High Power Range Neutron Flux (High Setpoint) channel inoperable.	-------------------NOTE-------------------- One channel may be bypassed for up to 12 hours for surveillance testing or setpoint adjustment, provided the other channels are OPERABLE or placed in the trip condition. --	
	E.1.1 Place channel in trip.	72 hours
	<u>AND</u>	
	E.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	78 hours
	<u>OR</u>	
	E.2.1 Place channel in trip.	72 hours
	<u>AND</u>	
	E.2.2 --------------NOTE-------------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. -------------------------------------	
	Perform SR 3.2.4.2.	Once per 12 hours
	<u>OR</u>	
	E.3 Be in MODE 3.	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One channel inoperable.	-------------------NOTE-------------------- One channel may be bypassed for up to 12 hours for surveillance testing, provided the other channels are OPERABLE or placed in the trip condition. ---	
	F.1 Place channel in trip.	72 hours
	OR	
	F.2 Be in MODE 3.	78 hours
G. One High Intermediate Range Neutron Flux channel inoperable.	G.1 Reduce THERMAL POWER to < P-6.	24 hours
	OR	
	G.2 Increase THERMAL POWER to > P-10.	24 hours
H. Two High Intermediate Range Neutron Flux channels inoperable.	H.1 --------------NOTE-------------- Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM. -------------------------------------	
	Suspend operations involving positive reactivity additions.	Immediately
	AND	
	H.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One High Source Range Neutron Flux channel inoperable.	--------------------NOTE------------------- Limited plant cooldown or boron dilution is allowed provided the change is accounted for in the calculated SDM. --- I.1 Suspend operations involving positive reactivity additions.	 Immediately
J. Two High Source Range Neutron Flux channels inoperable.	J.1 Open reactor trip breakers (RTBs).	Immediately
K. One High Source Range Neutron Flux channel inoperable.	K.1 Restore channel to OPERABLE status. <u>OR</u> K.2.1 Initiate action to fully insert all rods. <u>AND</u> K.2.2. Place the Rod Control System in a condition incapable of rod withdrawal.	48 hours 48 hours 49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One required channel inoperable.	-------------------NOTE-------------------- One required channel may be bypassed for up to 12 hours for surveillance testing, provided the other required channels are OPERABLE or placed in the trip condition. ---	
	L.1 Place channel in trip.	72 hours
	OR	
	L.2 Reduce THERMAL POWER to < P-7.	78 hours
M. One required train inoperable.	--------------------NOTE------------------- One required train may be bypassed for up to 4 hours for surveillance testing, provided the other required trains are OPERABLE. ---	
	M.1 Restore train to OPERABLE status.	24 hours
	OR	
	M.2 Be in MODE 3.	30 hours
N. One required RTB train inoperable.	N.1 Restore train to OPERABLE status.	24 hours
	[OR	
	N.2 Apply the requirements of 5.5.18.	24 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
O. One or more channels inoperable.	O.1 Verify interlock is in required state for existing unit conditions. OR O.2 Be in MODE 3.	1 hour 7 hours
P. One or more trains inoperable or one or more required channels inoperable.	P.1 Verify interlock is in required state for existing unit conditions. OR P.2 Be in MODE 2.	1 hour 7 hours
Q. One trip mechanism inoperable for a required RTB.	Q.1 Restore inoperable trip mechanism to OPERABLE status. [OR Q.2 Apply the requirements of Specification 5.5.18.	48 hours 48 hours]
R. One required train inoperable.	--------------------NOTE------------------- One required train may be bypassed for up to 4 hours for surveillance testing, provided the other required trains are OPERABLE. --- R.1 Restore train to OPERABLE status. [OR R.2 Apply the requirements of Specification 5.5.18.	 24 hours 24 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
S. Required Action and associated Completion Time for Condition N, Q, or R not met.	S.1 Be in MODE 3.	6 hours
T. One Main Turbine Stop Valve Position channel inoperable	--------------------NOTE------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	T.1 Place channel in trip.	12 hours
	OR	
	T.2 Reduce THERMAL POWER to <P-7.	18 hours
U. One required channel inoperable.	U.1 Place channel in trip.	1 hour
	AND	
	U.2 Restore channel to OPERABLE status.	72 hours
V. Required Action and associated Completion Time of Condition U not met.	V.1 Be in MODE 3.	6 hours
W. One required channel inoperable.	W.1 Place channel in trip.	1 hour
	AND	
	W.2 Restore channel to OPERABLE status.	72 hours
X. Required Action and associated Completion Time of Condition W not met.	X.1 Reduce THERMAL POWER to < P-7.	6 hours

SURVEILLANCE REQUIREMENTS

--NOTE--
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.2	-----------------------------NOTE-------------------------- Not required to be performed until 12 hours after THERMAL POWER is ≥ 15% RTP. --- Compare results of calorimetric heat balance calculation to power range channel output. Adjust power range channel output if calorimetric heat balance calculations results exceed power range channel output by more than +2% RTP.	[24 hours OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.3	-----------------------------NOTE---------------------------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. -- Compare results of the incore detector measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	[31 effective full power days (EFPD) OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.4	Perform TADOT.	[62 days on a STAGGERED TEST BASIS OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.5	-----------------------------NOTE-------------------------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. --- Calibrate excore channels to agree with incore detector measurements.	[92 EFPD OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.6	Perform MIC consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.7	Perform CHANNEL CHECK.	Within 4 hours after reducing power below P-6 <u>AND</u> [Every 12 hours thereafter OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.8	Perform CHANNEL CALIBRATION consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.9	-----------------------------NOTE-------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.10	Perform CHANNEL CALIBRATION consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.1.11	Perform TADOT.	Prior to exceeding the P-7 interlock whenever the unit has been in MODE 3, if not performed within the previous 31 days
SR 3.3.1.12	-----------------------------NOTE-------------------------- Neutron detectors are excluded from response time testing. --- Verify RTS RESPONSE TIME is within limit.	[24 months on a STAGGERED TEST BASIS OR In accordance with the Surveillance Frequency Control Program]

Table 3.3.1-1 (page 1 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
1. Manual Reactor Trip Initiation	1,2	3 trains	B	SR 3.3.1.4
	3[a], 4[a], 5[a]	3 trains	C	SR 3.3.1.4
2. High Power Range Neutron Flux				
a. High Setpoint	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12
b. Low Setpoint	1[b],2	4	F	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12
3. High Power Range Neutron Flux Rate				
a. Positive Rate	1,2	4	F	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12
b. Negative Rate	1,2	4	F	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12
4. High Intermediate Range Neutron Flux	1[b], 2[c]	2	G,H	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12

(a) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 2 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
5. High Source Range Neutron Flux	2(d)	2	I,J	SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.9 SR 3.3.1.12
	3(a), 4(a), 5(a)	2	J,K	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.9 SR 3.3.1.12
6. Overtemperature ΔT	1,2	3	U,V	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.5 SR 3.3.1.6 SR 3.3.1.10 SR 3.3.1.12

(a) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
7. Overpower ΔT	1,2	3	U,V	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.5 SR 3.3.1.6 SR 3.3.1.10 SR 3.3.1.12
8. Pressurizer Pressure				
a. Low Pressurizer Pressure	1(e)	3	W,X	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
b. High Pressurizer Pressure	1,2	3	U,V	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
9. High Pressurizer Water Level	1(e)	3	W,X	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
10. Low Reactor Coolant Flow	1(e)	3 per loop	L	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
11. Low Reactor Coolant Pump (RCP) Speed	1(e)	3	L	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
12. Steam Generator (SG) Water Level				
a. Low	1,2	3 per SG	U,V	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
b. High-High	1(e)	3 per SG	W,X	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8 SR 3.3.1.12
13. Turbine Trip				
a. Turbine Emergency Trip Oil Pressure	1(e)	3	L	SR 3.3.1.8 SR 3.3.1.11
b. Main Turbine Stop Valve Position	1(e)	1 per valve	T	SR 3.3.1.8 SR 3.3.1.11

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
14.ECCS actuation	1,2	3 trains	M	SR 3.3.1.6
15.Reactor Trip System Interlocks				
a. Intermediate Range Neutron Flux, P-6	2[(d)]	2	O	SR 3.3.1.6 SR 3.3.1.9
b. Low Power Reactor Trips Block, P-7	1	1 per train	P	SR 3.3.1.6
c. Power Range Neutron Flux, P-10	1,2	4	O	SR 3.3.1.6 SR 3.3.1.9
d. Turbine Inlet Pressure, P-13	1	3	P	SR 3.3.1.1 SR 3.3.1.6 SR 3.3.1.8
16.Reactor Trip Breakers (RTBs)	1,2	3 trains[(f)]	N,S	SR 3.3.1.4 SR 3.3.1.12
	3[(a)], 4[(a)], 5[(a)]	3 trains[(f)]	D	SR 3.3.1.4 SR 3.3.1.12

(a) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(f) Two reactor trip breakers per train.

Table 3.3.1-1 (page 6 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
17. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	3 trains 1 each per RTB	Q,S	SR 3.3.1.4 SR 3.3.1.12
	3[a], 4[a], 5[a]	3 trains 1 each per RTB	D	SR 3.3.1.4 SR 3.3.1.12
18. Automatic Trip Logic	1,2	3 trains	R,S	SR 3.3.1.6
	3[a], 4[a], 5[a]	3 trains	D	SR 3.3.1.6

(a) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One required train inoperable.	B.1 Restore train to OPERABLE status.	72 hours
	<u>OR</u>	
	B.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	B.2.2 Be in MODE 5.	108 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	--------------------NOTE------------------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other train(s) are OPERABLE. --	
	C.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	C.2.1 Be in MODE 3.	30 hours
	<u>AND</u>	
	C.2.2 Be in MODE 5.	60 hours
D. One required channel inoperable.	------------------NOTE--------------------- One required channel may be bypassed for up to 12 hours for surveillance testing, provided the other required channels are OPERABLE or placed in the trip condition. --	
	D.1 Place channel in trip.	72 hours
	<u>OR</u>	
	D.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	D.2.2 Be in MODE 4.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One required Containment Pressure channel inoperable.	--------------------NOTE------------------- One required channel may be bypassed for up to 12 hours for surveillance testing, provided the other required channels are OPERABLE. ---	
	E.1 Restore channel to OPERABLE status.	72 hours
	OR	
	E.2.1 Be in MODE 3.	78 hours
	AND	
	E.2.2 Be in MODE 4.	84 hours
F. One channel or required train inoperable.	------------------NOTE--------------------- One Loss of Offsite Power channel may be bypassed for up to 4 hours for surveillance testing, provided the other channels are OPERABLE or placed in the trip condition. ---	
	F.1 Restore channel or train to OPERABLE status.	72 hours
	OR	
	F.2.1 Be in MODE 3.	78 hours
	AND	
	F.2.2 Be in MODE 4.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One train inoperable.	--------------------NOTE------------------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. --	
	G.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	G.2.1 Be in MODE 3.	30 hours
	<u>AND</u>	
	G.2.2 Be in MODE 4.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One required Main Feedwater Pumps trips channel inoperable.	H.1 Restore channel to OPERABLE status. OR H.2 Be in MODE 3.	48 hours 54 hours
I. One or more required Pressurizer Pressure, P-11 channels inoperable.	I.1 Verify interlock is in required state for existing unit condition. OR I.2.1 Be in MODE 3. AND I.2.2 Be in MODE 4.	1 hour 7 hours 13 hours
J. One required Emergency Feedwater Actuation train inoperable.	--------------------NOTE------------------- One required train may be bypassed for up to 4 hours for surveillance testing, provided the other required trains are OPERABLE. --- J.1 Restore train to OPERABLE status. [OR J.2 Apply the requirements of Specification 5.5.18.	 72 hours 72 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
K. One required Containment High Range Area Radiation channel inoperable.	K.1 Restore channel to OPERABLE status.	72 hours
L. One or more Containment Purge Isolation trains inoperable. <u>OR</u> Two or more required Containment High Range Area Radiation channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition K not met.	L.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment purge and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One required channel inoperable.	M.1 Place channel in trip. AND M.2 Restore channel to OPERABLE status.	1 hour 72 hours
N. Required Action and associated Completion Time of Condition M not met.	N.1 Be in MODE 3. AND N.2 Be in MODE 4.	6 hours 12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
O. One S-VDU train inoperable.	--------------------NOTE-------------------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other trains are OPERABLE. --	
	O.1 Restore train to OPERABLE status.	72 hours
	<u>OR</u>	
	O.2 Enter applicable Conditions and Required Actions for the ESF components made inoperable by the inoperable S-VDU train.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
P. One COM-2 train inoperable.	--------------------NOTE-------------------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other trains are OPERABLE. ---	
	P.1 Restore train to OPERABLE status.	12 hours
	OR	
	P.2 Enter applicable Conditions and Required Actions for the ESF components made inoperable by the inoperable COM-2 train.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. One required train inoperable.	--------------------NOTE------------------- One required train may be bypassed for up to 4 hours for surveillance testing, provided the other required trains are OPERABLE. ---	
	Q.1 Restore train to OPERABLE status.	24 hours
	[<u>OR</u>	
	Q.2 -------------NOTE--------------- This Required Action is not applicable in MODE 4. ------------------------------------	
	Apply the requirements of Specification 5.5.18.	24 hours]
R. Required Action and associated Completion Time for Condition Q not met.	R.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	R.2 Be in MODE 5.	36 hours
S. One train inoperable.	--------------------NOTE------------------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other trains are OPERABLE. ---	
	S.1 Restore train to OPERABLE status.	24 hours
	[<u>OR</u>	
	S.2 Apply the requirements of Specification 5.5.18.	24 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
T. Required Action and associated Completion Time for Condition J or S not met.	T.1 Be in MODE 3. AND T.2 Be in MODE 4.	6 hours 12 hours
U. One or more MCR Outside Air Intake Radiation Functions with one channel inoperable.	U.1 Place one MCREFS train and two MCRATCS trains in the emergency mode.	7 days
V. One or more MCR Outside Air Intake Radiation Functions with two channels inoperable.	V.1 Place one MCREFS train and two MCRATCS trains in the emergency mode. AND V.2.1 Restore one channel to OPERABLE status. OR V.2.2 Place two MCREFS trains and three MCRATCS trains in the emergency mode.	Immediately 7 days 7 days
W. One or more Functions with one train, A or D, inoperable.	--------------------NOTE------------------- This condition is only applicable to Train A or D. For inoperable Train B or C there is no action required. -- W.1 Place the affected train of MCREFS in the emergency mode.	 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
X. One or more Functions with two trains, A and D, inoperable.	--------------------NOTE------------------- This condition is only applicable to Trains A and D. Other inoperable two-train combinations are addressed in Condition Y. ---	
	X.1 Place one MCREFS train in the emergency mode.	Immediately
	AND	
	X.2.1 Restore one MCREFS train to OPERABLE status (i.e., one train in the emergency mode and one train OPERABLE).	7 days
	OR	
	X.2.2 Place two MCREFS trains in the emergency mode.	7 days
	AND	
	X.3.1 Restore one affected MCRATCS train to OPERABLE status (i.e., three trains OPERABLE).	7 days
	OR	
	X.3.2 Place one affected MCRATCS train in the emergency mode (i.e., one train in the emergency mode and two trains OPERABLE).	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Y. One or more Functions with two trains, except A and D, inoperable.	--------------------NOTE------------------- Inoperable Train A or D affects MCREFS and MCRATCS. Inoperable Train B or C affects MCRATCS. --	
	Y.1 Restore one affected train to OPERABLE status for the affected subsystem(s).	7 days
	<u>OR</u>	
	Y.2 Place one affected train in the emergency mode for the affected subsytem(s).	7 days
Z. Required Action and associated Completion Time for Condition U, V, W, X or Y not met in MODE 1, 2, 3, or 4.	Z.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	Z.2 Be in MODE 5.	36 hours
AA. Required Action and associated Completion Time for Condition U, V, W, X or Y not met during movement of irradiated fuel assemblies.	AA.1 Suspend movement of irradiated fuel assemblies.	Immediately
BB. One required Reactor Trip, P-4 train inoperable.	BB.1 Restore train to OPERABLE status.	48 hours
	<u>OR</u>	
	BB.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	BB.2.2 Be in MODE 4.	60 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.2.2	Perform MIC consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.3	Perform TADOT for Actuation Outputs.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.2.4	Perform TADOT.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.2.5	Perform TADOT.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.6	Perform CHANNEL CALIBRATION consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.2.7	------------------------------NOTE--------------------------- Not required to be performed for the turbine driven EFW pumps until 24 hours after SG pressure is ≥ 1000 psig. --- Verify ESF RESPONSE TIME is within limit.	[24 months on a STAGGERED TEST BASIS OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.2.8	Perform TADOT.	Once per reactor trip breaker cycle

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.9	Perform SAFETY VDU TEST.	[24 months OR In accordance with the Surveillance Frequency Control Program]

Table 3.3.2-1 (page 1 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
1. ECCS Actuation				
a. Manual Initiation	1,2,3,4	3 trains	B	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3,4	3 trains	Q,R	SR 3.3.2.2 SR 3.3.2.3
c. High Containment Pressure	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
d. Low Pressurizer Pressure	1,2,3[(a)]	3	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
e. Low Main Steam Line Pressure	1,2,3[(a)]	3 per steam line	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

(a) Above the P-11 (Pressurizer Pressure) interlock.

Table 3.3.2-1 (page 2 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
2. Containment Spray				
a. Manual Initiation	1,2,3,4	2 switches per train for 4 trains	B	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3,4	3 trains	Q,R	SR 3.3.2.2 SR 3.3.2.3
c. High-3 Containment Pressure	1,2,3	3	E	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

Table 3.3.2-1 (page 3 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
3. Containment Isolation				
a. Phase A Isolation				
(1) Manual Initiation	1,2,3,4	Trains A and D	B	SR 3.3.2.5
(2) Actuation Logic and Actuation Outputs	1,2,3,4	Trains A and D	C	SR 3.3.2.2 SR 3.3.2.3
(3) ECCS Actuation	Refer to Function 1 (ECCS Actuation) for all requirements.			
b. Phase B Isolation				
(1) Containment Spray - Manual Initiation	Refer to Function 2.a (Containment Spray - Manual Initiation) for all requirements.			
(2) Actuation Logic and Actuation Outputs	1,2,3,4	4 trains	C	SR 3.3.2.2 SR 3.3.2.3
(3) High-3 Containment Pressure	Refer to Function 2.c (Containment Spray - High-3 Containment Pressure) for all requirements.			

Table 3.3.2-1 (page 4 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
4. Main Steam Line Isolation				
a. Manual Initiation	1,2,3	Trains A and D	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	Trains A and D	S,T	SR 3.3.2.2 SR 3.3.2.3
c. High-High Containment Pressure	1, 2, 3	3	D	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
d. Main Steam Line Pressure				
(1)Low Main Steam Line Pressure	1, 2, 3 (a)	3 per steam line	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
(2)High Main Steam Line Pressure Negative Rate	3 (b)	3 per steam line	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

(a) Above the P-11 (Pressurizer Pressure) interlock.

(b) Below the P-11 (Pressurizer Pressure) interlock.

Table 3.3.2-1 (page 5 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
5. Main Feedwater Isolation				
a. Manual Initiation	1,2,3	Trains A and D	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	Trains A and D	S,T	SR 3.3.2.2 SR 3.3.2.3
c. High-High SG Water Level	1,2,3[(c)]	3 per SG	M,N,	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
d. ECCS Actuation	Refer to Function 1 (ECCS Actuation) for all requirements.			
e. Low T_{avg}[(d)]	1,2,3	3	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
Coincident with Reactor Trip, P-4	Refer to Function 11.a (ESFAS Interlocks - Reactor Trip, P-4) for all requirements.			

(c) The sub-function for trip of all MWF pumps, and closure of the MFIVs and SGWFCVs may be manually bypassed in MODE 3 below the P-11 (Pressurizer Pressure) interlock.

(d) Low T_{avg} coincident with Reactor Trip, P-4 only closes MFW Regulation valves.

Table 3.3.2-1 (page 6 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
6. Emergency Feedwater Actuation				
a. Manual Initiation	1,2,3	3 trains	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	3 trains	J,T	SR 3.3.2.2 SR 3.3.2.3
c. Low SG Water Level	1,2,3	3 per SG	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
d. ECCS Actuation	Refer to Function 1 (ECCS Actuation) for all requirements.			
e. LOOP Signal	1,2,3	3 per bus for each EFW train	F	SR 3.3.2.4 SR 3.3.2.6 SR 3.3.2.7
f. Trip of all Main Feedwater Pumps	1,2	1 per pump	H	SR 3.3.2.5 SR 3.3.2.7

Table 3.3.2-1 (page 7 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
7. Emergency Feedwater Isolation				
a. Manual Initiation	1,2,3	2 trains per SG	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	2 trains per SG	G	SR 3.3.2.2 SR 3.3.2.3
c. High SG Water Level	1,2,3 (a)	3 per SG	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
Coincident with Reactor Trip, P-4	Refer to Function 11.a (ESFAS Interlocks - Reactor Trip, P-4) for all requirements.			
and				
No Low Main Steam Line Pressure	Refer to Function 7.d (Emergency Feedwater Isolation - Low Main Steam Line Pressure) for all requirements.			
d. Low Main Steam Line Pressure	1,2,3 (a)	3 per SG	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
8. CVCS Isolation				
a. Manual Initiation	1,2,3	Trains A and D	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	Trains A and D	G	SR 3.3.2.2 SR 3.3.2.3
c. High Pressurizer Water Level	1,2,3 (a)	3	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

(a) Above the P-11 (Pressurizer Pressure) interlock.

Table 3.3.2-1 (page 8 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
9. Turbine Trip				
a. Actuation Logic and Actuation Outputs	1,2,3	Trains A and D	G	SR 3.3.2.2 SR 3.3.2.3
b. Reactor Trip, P-4	Refer to Function 11.a (ESFAS Interlocks - Reactor Trip, P-4) for all requirements.			
c. High-High SG Water Level	1,2,3	3 per SG	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
10. Reactor Coolant Pump Trip				
a. ECCS Actuation	Refer to Function 1 (ECCS Actuation) for allrequirements.			
Coincident with Reactor Trip, P-4	Refer to Function 11.a (ESFAS Interlocks - Reactor Trip, P-4) for all requirements.			
11. ESFAS Interlocks				
a. Reactor Trip, P-4	1,2,3	3 trains	BB	SR 3.3.2.8
b. Pressurizer Pressure, P-11	1,2,3	3	I	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6

Table 3.3.2-1 (page 9 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
12. Containment Purge Isolation				
a. Containment Isolation Phase A - Manual Initiation	Refer to Function 3.a.(1) (Containment Isolation - Phase A Isolation - Manual Initiation) for all requirements.			
b. Containment Spray - Manual Initiation	Refer to Function 2.a (Containment Spray - Manual Initiation) for all and requirements.			
c. Actuation Logic and Actuation Outputs	1,2,3,4	Trains A and D	L	SR 3.3.2.2 SR 3.3.2.3
d. ECCS Actuation	Refer to Function 1 (ECCS Actuation) for all requirements.			
e. Containment High Range Area Radiation	1,2,3,4	3	K, L	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

Table 3.3.2-1 (page 10 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
13. Main Control Room (MCR) Isolation				
a. Manual Initiation	1,2,3,4,(e)	3 trains including A and D(f)	W, X, Y, Z, AA	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3,4,(e)	3 trains including A and D(f)	W, X, Y, Z, AA	SR 3.3.2.2 SR 3.3.2.3
c. MCR Outside Air Intake Radiation				
(1) MCR Outside Air Intake Gas Radiation	1,2,3,4,(e)	2	U, V, Z, AA	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
(2) MCR Outside Air Intake Particulate Radiation	1,2,3,4,(e)	2	U, V, Z, AA	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
(3) MCR Outside Air Intake Iodine Radiation	1,2,3,4,(e)	2	U, V, Z, AA	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
d. ECCS Actuation	Refer to Function 1 (ECCS Actuation) for all requirements.			

(e) During movement of irradiated fuel assemblies.

(f) Two trains of MCREFS are required to be operable (trains A and D); three trains of MCRATS are required to be operable (three out of four trains A, B, C, D).

Table 3.3.2-1 (page 11 of 11)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
14. Block Turbine Bypass and Cooldown Valves				
a. Manual Initiation	1,2,3	Trains A and D	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	Trains A and D	S,T	SR 3.3.2.2 SR 3.3.2.3
c. Low-Low T_{avg} Signal	1,2,3[(g)]	3	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7
15. Manual Control of ESF Components				
a. Safety VDU	1, 2, 3, 4, 5, 6	4 trains	O	SR 3.3.2.2 SR 3.3.2.9
b. COM-2	1, 2, 3, 4, 5, 6	4 trains	P	SR 3.3.2.2
c. Actuation Logic and Actuation Outputs	Refer to LCO 3.4 through 3.7 for all requirements applicable to the controlled ESF components.			SR 3.3.2.2 SR 3.3.2.3
16. Main Steam Relief Line Isolation				
a. Manual Initiation	1,2,3	2 trains per SG	F	SR 3.3.2.5
b. Actuation Logic and Actuation Outputs	1,2,3	2 trains per SG	G	SR 3.3.2.2 SR 3.3.2.3
c. Low Main Steam Line Pressure	1,2,3[(h)]	3 per SG	M,N	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.7

(g) Low-Low T_{avg} Signal for Cooldown Turbine Bypass Valves is required to be OPERABLE in MODE 3 above the setpoint of Low-Low T_{avg}. Low-Low T_{avg} Signal for Turbine Bypass Valves (except Cooldown Turbine Bypass Valves) is required to be OPERABLE in MODE 3.

(h) Except while manual cooling operation with MSRV or MSDV by the operator.

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM Instrumentation Function in Table 3.3.3-1, and for all four trains of the PAM Display Function, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PAM Instrumentation Functions with one required channel inoperable. <u>OR</u> One train of the PAM Display Function inoperable.	A.1 Restore channel or train to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.5.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more PAM Instrumentation Functions with two required channels inoperable. OR Two trains of the PAM Display Function inoperable.	C.1 Restore one train or one required channel to OPERABLE status. [OR C.2 --------------NOTE------------- This alternate action may be used only when the Emergency Feedwater Pit Level is inoperable. ------------------------------------ Apply the requirements of Specification 5.5.18.	7 days 7 days]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM Instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.3.2	----------------------------NOTE--------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.3.3	Perform MIC for the PAM Instrumentation.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.3.4	Perform SAFETY VDU TEST for all four trains of the PAM Display Function.	[24 months OR In accordance with the Surveillance Frequency Control Program]

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS
1.	Wide Range Neutron Flux	2
2.	Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	3
3.	RCS Cold Leg Temperature (Wide Range)	3
4.	RCS Pressure (Wide Range)	2
5.	Reactor Vessel Water Level	2[d]
6.	Containment Pressure	2
7.	Containment Isolation Valve Position	2 per penetration flow path[a][b]
8.	Containment High Range Area Radiation	2
9.	Pressurizer Water Level	2
10.	Steam Generator Water Level (Wide Range)	1 per SG
11.	Steam Generator Water Level (Narrow Range)	2 per SG
12.	Core Exit Temperature - Quadrant 1	4[c]
13.	Core Exit Temperature - Quadrant 2	4[c]
14.	Core Exit Temperature - Quadrant 3	4[c]
15.	Core Exit Temperature - Quadrant 4	4[c]
16.	Emergency Feedwater Flow	1 per SG
17.	Degrees of Subcooling	2
18.	Main Steam Line Pressure	2 per SG
19.	Emergency Feedwater Pit Level	2
20.	Refueling Water Storage Pit Level (Wide Range)	2
21.	Refueling Water Storage Pit Level (Narrow Range)	2

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Two thermocouple channels are required from each of two trains. For each train, one thermocouple channel is required near the center of the core and one thermocouple channel is required near the core perimeter.

(d) A channel consists of three sections with two sensors per section. A channel is OPERABLE if at least one sensor is OPERABLE in all three sections.

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown Console (RSC)

LCO 3.3.4 The RSC shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required channel or train inoperable for the Display and Control Function <u>OR</u> One train inoperable for the Transfer of Control Function.	A.1 Restore channel or train to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform TADOT for Transfer Switches.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.4.2	Perform SAFETY VDU TEST for all four trains of the RSC Display Function.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.4.3	Perform CHANNEL CHECK for each RSC Instrumentation Function.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.4.4	------------------------------NOTE------------------------------ Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION for each RSC Instrumentation Function.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.5	Perform MIC for the RSC.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.4.6	Perform TADOT for Actuation Outputs of each RCS Control Function.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Class 1E Gas Turbine Generator (GTG) Start Instrumentation

LCO 3.3.5 The following Loss of Power (LOP) Class 1E Gas Turbine Generator (GTG) Start Instrumentation shall be OPERABLE.

a. Three channels per required bus of the loss of voltage Function and three channels per required bus of the degraded voltage Function, and

b. One train per required bus of the LOP Actuation Function.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated Class 1E GTG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel per required bus inoperable.	A.1 --------------NOTE-------------- One channel may be bypassed for up to 4 hours for surveillance testing, provided the other channel on the same bus are operable or placed in the trip condition. ------------------------------------- Place channel in trip.	6 hours
B. One or more Functions with two or more channels per required bus inoperable.	B.1 Restore all but one channel per required bus to OPERABLE status.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train of the LOP Actuation Function per required bus inoperable. OR Required Action and associated Completion Time of Conditions A or B not met.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated Class 1E GTG made inoperable by LOP Class 1E GTG Start Instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform TADOT for LOP undervoltage relays.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.5.2	Perform CHANNEL CALIBRATION for the following LOP undervoltage relays consistent with Specification 5.5.21, Setpoint Control Program (SCP). a. Loss of voltage b. Degraded voltage	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.5.3	Perform MIC for LOP Class 1E GTG Start Instrumentation.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.5.4	Perform TADOT for GTG control outputs.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.3 INSTRUMENTATION

3.3.6 Diverse Actuation System (DAS) Instrumentation

LCO 3.3.6 DAS for each function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6-1.

ACTION

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions, with one or more subsystems or required channels inoperable.	-------------------NOTES------------------ 1. The Actuation Logic of one subsystem, or one required channel may be bypassed for up to 4 hours for surveillance testing, provided the Actuation Logic in the other subsystems or the other required channels are OPERABLE. 2. The Actuation Outputs of two subsystems may be bypassed for up to 4 hours for surveillance testing of the Actuation Outputs from the other subsystems, or surveillance testing of the Rod Drive Motor-Generator Set Trip Devices. --	
	A.1 Restore subsystem or channel to OPERABLE status.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.1 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.6-1 to determine which SRs apply for each DAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.6.2	Perform COT consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.6.3	-----NOTE----- The CHANNEL CALIBRATION conducted for the PSMS in LCO 3.3.1 or 3.3.2 may be credited for DAS. ---------- Perform CHANNEL CALIBRATION consistent with Specification 5.5.21, Setpoint Control Program (SCP).	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.6.4	Perform ACTUATION LOGIC TEST.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.5	Perform TADOT for the Manual Initiation/Control and Actuation Outputs.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.3.6.6	Perform TADOT for the Rod Drive Motor-Generator set trip devices.	[24 months OR In accordance with the Surveillance Frequency Control Program]

Table 3.3.6-1 (page 1 of 2)
Diverse Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
1. Reactor Trip/ Turbine Trip/ MFW Isolation				
a. Manual Initiation	1,2,3[(a)]	1[(b)]	A,B	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3[(a)]	4 subsystems	A,B	SR 3.3.6.4 SR 3.3.6.5
c. Low Pressurizer Pressure	1,2,3[(a)]	3[(c)]	A,B	SR 3.3.6.1 SR 3.3.6.2 SR 3.3.6.3
d. High Pressurizer Pressure	1,2,3[(a)]	3[(c)]	A,B	SR 3.3.6.1 SR 3.3.6.2 SR 3.3.6.3
e. Low Steam Generator Water Level	1,2,3[(a)]	1[(c)] per SG for any 3 SGs	A,B	SR 3.3.6.1 SR 3.3.6.2 SR 3.3.6.3
f. Rod Drive Motor-Generator Set Trip Device	1,2,3[(a)]	2 subsystems (1 for each MG-Set)	A,B	SR 3.3.6.6
2. EFWS Actuation				
a. Manual Initiation	1,2,3[(a)]	1[(b)]	A,B	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3[(a)]	4 subsystems	A,B	SR 3.3.6.5
c. Low Steam Generator Water Level	Refer to Function 1.e (Reactor Trip/ Turbine Trip/ MFW Isolation - Low Steam Generator Water Level) for all requirements.			

(a) With the Pressurizer Pressure > P-11

(b) Manual Initiation and Manual Control Functions require operation of 2 switches on the DHP: (1) The Permissive Switch for DAS HSI, which is common to all Manual Initiation and Manual Control Functions, and (2) the Manual Initiation or Manual Control switch, which is unique for each Function. Therefore, a channel consists of both switches and their respective interfaces to two of the four DAAC subsystems.

(c) Required channels for each of the four DAAC subsystems must be OPERABLE.

Table 3.3.6-1 (page 2 of 2)
Diverse Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS
3. ECCS Actuation				
a. Manual Initiation	1,2,3(a)	1(b)	A,B	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3(a)	4 subsystems	A,B	SR 3.3.6.4 SR 3.3.6.5
c. Low-Low Pressurizer Pressure	1,2,3(a)	3(c)	A,B	SR 3.3.6.1 SR 3.3.6.2 SR 3.3.6.3
4. Containment Isolation				
a. Manual Initiation	1,2,3(a)	1(b)	A,B	SR 3.3.6.5
5. EFW Isolation Valves				
a. Manual Control	1,2,3(a)	1(b) for each SG	A,B	SR 3.3.6.5
6. Pressurizer Safety Depressurization Valves				
a. Manual Control	1,2,3(a)	1(b)	A,B	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3(a)	4 subsystems	A,B	SR 3.3.6.4 SR 3.3.6.5
7. Main Steam Depressurization Valves				
a. Manual Control	1,2,3(a)	1(b) for each SG	A	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3(a)	4 subsystems	A,B	SR 3.3.6.4 SR 3.3.6.5
8. Main Steam Line Isolation				
a. Manual Initiation	1,2,3(a)	1(b)	A,B	SR 3.3.6.5
b. Actuation Logic and Actuation Outputs	1,2,3(a)	4 subsystems	A,B	SR 3.3.6.4 SR 3.3.6.5

(a) With the Pressurizer Pressure > P-11

(b) Manual Initiation and Manual Control Functions require operation of 2 switches on the DHP: (1) The Permissive Switch for DAS HSI, which is common to all Manual Initiation and Manual Control Functions, and (2) the Manual Initiation or Manual Control switch, which is unique for each Function. Therefore, a channel consists of both switches and their respective interfaces to two of the four DAAC subsystems.

(c) Required channels for each of the four DAAC subsystems must be OPERABLE.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure is greater than or equal to the limit specified in the COLR,

b. RCS average temperature is less than or equal to the limit specified in the COLR, and

c. RCS total flow rate ≥ 460,000 gpm and greater than or equal to the limit specified in the COLR.

APPLICABILITY: MODE 1.

--NOTE--

Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is greater than or equal to the limit specified in the COLR.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.1.2	Verify RCS average temperature is less than or equal to the limit specified in the COLR.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.1.3	Verify RCS total flow rate is ≥ 460,000 gpm and greater than or equal to the limit specified in the COLR.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.1.4	------------------------------NOTE------------------------- Not required to be performed until 24 hours after ≥ 90% RTP. --- Verify by precision heat balance that RCS total flow rate is ≥ 460,000 gpm and greater than or equal to the limit specified in the COLR.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 551°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 2 with K_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each loop ≥ 551°F.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE---------- Required Action A.2 shall be completed whenever this Condition is entered. ------------------------------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits. <u>AND</u> A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5 with RCS pressure < 500 psig.	6 hours 36 hours
C. ------------NOTE---------- Required Action C.2 shall be completed whenever this Condition is entered. ------------------------------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits. <u>AND</u> C.2 Determine RCS is acceptable for continued operation.	Immediately Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	-------------------------------NOTE------------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	[30 minutes OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops - MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify each RCS loop is in operation.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops - MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

--NOTE--
All reactor coolant pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable.	A.1 Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required RCS loop not in operation with Rod Control System capable of rod withdrawal.	C.1 Restore required RCS loop to operation. OR C.2 Place the Rod Control System in a condition incapable of rod withdrawal.	1 hour 1 hour
D. Two required RCS loops inoperable. OR Required RCS loop(s) not in operation.	D.1 Place the Rod Control System in a condition incapable of rod withdrawal. AND D.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND D.3 Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 14% for required RCS loops.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.5.3	------------------------------NOTE------------------------- Not required to be performed until 24 hours after a required pump is not in operation. --- Verify correct breaker alignment and indicated power are available to each required pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops - MODE 4

LCO 3.4.6 Two RCS loops shall be OPERABLE and one RCS loop shall be in operation.

OR

Three Residual Heat Removal (RHR) loops shall be OPERABLE and two RHR loops shall be in operation and all sources of unborated water shall be isolated.

--NOTES--

1. All reactor coolant pumps (RCPs) and CS/RHR pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ the Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR unless the secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures.

3. Except as prohibited in Note 1 above, an isolation valve for an unborated water source may be opened when in a planned dilution or makeup activity.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required loop inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status. <u>AND</u>	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2 --------------NOTE-------------- Only required if two RHR loops are OPERABLE. ------------------------------------- Be in MODE 5.	 24 hours
B. Two or more required loops inoperable. <u>OR</u> Required loop(s) not in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. <u>AND</u> B.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately
C. -----------NOTE----------- Separate Condition entry is allowed for each unborated water source isolation valve. ------------------------------ -----------NOTE----------- Required Action C.2 must be completed whenever Condition C is entered. ------------------------------ One or more isolation valves for an unborated water source not secured in closed position.	C.1 Initiate actions to secure valve in closed position. <u>AND</u> C.2 Perform SR 3.1.1.1 (SDM verification)	Immediately 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify required RHR or RCS loops are in operation. If no RCS loops are in operation, perform SR 3.4.6.4.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.6.2	Verify SG secondary side water levels are ≥ 14% for required RCS loops.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.6.3	------------------------------NOTE------------------------- Not required to be performed until 24 hours after a required pump is not in operation. --- Verify correct breaker alignment and indicated power are available to each required pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.6.4	------------------------------NOTE------------------------- Not required to be performed unless no RCPs are in operation. --- Verify each valve that isolates unborated water sources is secured in the closed position.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.6.5	------------------------------NOTE------------------------- Not required to be performed until 12 hours after entering MODE 4. --- Verify required RHR loop locations susceptible to gas accumulation are sufficiently filled with water.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops - MODE 5, Loops Filled

LCO 3.4.7

Two residual heat removal (RHR) loops shall be OPERABLE and in operation, and all sources of unborated water shall be isolated and either:

a. One additional RHR loop shall be OPERABLE or

b. The secondary side water level of at least two steam generators (SGs) shall be ≥ 14%.

--NOTES--

1. The CS/RHR pumps of the loops in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

    a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other two RHR loops are OPERABLE and in operation.

3. No reactor coolant pump shall be started with one or more RCS cold leg temperatures ≤ the Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation. The requirement for isolation of the unborated water sources is removed as soon as one RCP is in operation.

5. Except as prohibited in Note 1 above, an isolation valve for an unborated water source may be opened when in a planned dilution or makeup activity.

APPLICABILITY: MODE 5 with RCS Loops Filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RHR loop inoperable. <u>OR</u> One or more required SGs with secondary side water level not within limit <u>AND</u> Two RHR loops OPERABLE and in Operation.	A.1 Initiate action to restore a third RHR loop to OPERABLE status <u>OR</u> A.2 Initiate action to restore required SGs secondary side water level to within limit.	Immediately Immediately
B. Less than two RHR loops OPERABLE or in operation. .	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. <u>AND</u> B.2 Initiate action to restore two RHR loops to OPERABLE status and operation.	Immediately Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. -----------NOTE----------- Separate Condition entry is allowed for each unborated water source isolation valve. ------------------------------ -----------NOTE----------- Required Action C.2 must be completed whenever Condition C is entered. ------------------------------ One or more isolation valves for an unborated water source not secured in closed position.	C.1 Initiate actions to secure valve in closed position. AND C.2 Perform SR 3.1.1.1 (SDM verification)	Immediately 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify required RHR loops are in operation.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.7.2	Verify SG secondary side water level is ≥ 14% in required SGs.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.7.3	------------------------------NOTE------------------------- Not required to be performed until 24 hours after a required pump is not in operation. --- Verify correct breaker alignment and indicated power are available to each required CS/RHR pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.7.4	------------------------------NOTE------------------------- Not required to be performed unless no RCPs are in operation. --- Verify each valve that isolates unborated water sources is secured in the closed position.	[7 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS

SR 3.4.7.5	Verify required RHR loop locations susceptible to gas accumulation are sufficiently filled with water.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops - MODE 5, Loops Not Filled

LCO 3.4.8 Three residual heat removal (RHR) loops shall be OPERABLE and two RHR loops shall be in operation, and low-pressure letdown line isolation valve shall be OPERABLE, and all sources of unborated water shall be isolated, with:

a. One OPERABLE safety injection (SI) pump, and

b. Required injection water volume from OPERABLE RWSP and refueling cavity.

---NOTES---

1. One CS/RHR pump may be removed from operation for ≤ 15 minutes when switching from one loop to another provided:

    a. The core outlet temperature is maintained > 10°F below saturation temperature,

    b. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    c. No draining operations to further reduce the RCS water volume are permitted.

2. One required RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other two RHR loops are OPERABLE and in operation.

3. Except as prohibited in Note 1 above, an isolation valve for an unborated water source may be opened when in a planned dilution or makeup activity.

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One low-pressure letdown isolation valve inoperable.	B.1 Initiate action to restore low-pressure letdown line isolation valve to OPERABLE status.	Immediately
C. Less than two required RHR loops OPERABLE. OR Less than two Required RHR loops in operation.	C.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND C.2 Initiate action to restore two RHR loops to OPERABLE status and operation.	Immediately Immediately
D. -----------NOTE----------- Separate Condition entry is allowed for each unborated water source isolation valve. ----------------------------- -----------NOTE----------- Required Action D.2 must be completed whenever Condition D is entered. ----------------------------- One or more isolation valves for an unborated water source not secured in closed position.	D.1 Initiate actions to secure valve in closed position. AND D.2 Perform SR 3.1.1.1 (SDM verification)	Immediately 4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. No SI pump is OPERABLE. OR RWSP and refueling cavity water volume is not within limits. OR RWSP boron concentration is not within limits.	E.1 Initiate action to restore OPERABILITY of SI pump. AND E.2 Initiate actions to suspend activities that may cause a reduction in RCS water volume. AND E.3 Initiate actions to restore RWSP and refueling cavity water volume to within limits. AND E.4 Initiate actions to restore RWSP boron concentration to within limits.	Immediately Immediately Immediately Immediately
F. No RHR loop is in operation.	F.1 Close the equipment hatch and secure with [four] bolts. AND F.2 Close one door in each air lock. AND F.3.1 Close each penetration providing direct access from the containment atmosphere to the outside atmosphere with a manual or automatic isolation valve, blind flange, or equivalent. OR F.3.2 Verify each penetration is capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.	4 hours 4 hours 4 hours 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify required RHR loops are in operation.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.2	-------------------------------NOTE-------------------------- Not required to be performed until 24 hours after a required pump is not in operation. --- Verify correct breaker alignment and indicated power are available to each required CS/RHR pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.3	Perform a complete cycle of each low-pressure letdown line isolation valve.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.8.4	------------------------------NOTE------------------------- Not required to be performed unless no RCPs are in operation. --- Verify each valve that isolates unborated water sources is secured in the closed position.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.5	Verify RHR loop locations susceptible to gas accumulation are sufficiently filled with water.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.6	Verify the RWSP borated water volume (including water available in the refueling cavity) is $\geq$ 79,920 ft^3 (597,800 gallons).	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.7	Verify that the RWSP boron concentration is $\geq$ 4000 ppm and $\leq$ 4200 ppm.	[7 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.8.8	Verify the correct breaker alignment and indicated power is available to the required SI pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.8.9	Verify that one SI pump is capable of supplying developed head at the test flow point greater than or equal to the required developed head following a manual start.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 60% (MODE 1)
Pressurizer water level ≤ 92% (MODES 2 and 3) and

b. Three groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 120 kW and capable of being powered from an emergency power supply.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3. AND A.2 Fully insert all rods. AND A.3 Place Rod Control System in a condition incapable of rod withdrawal. AND A.4 Be in MODE 4.	6 hours 6 hours 6 hours 12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 60% in MODE 1, or ≤ 92% in MODES 2 and 3.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 120 kW.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Four pressurizer safety valves shall be OPERABLE with lift settings ≥ 2435 psig and ≤ 2485 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures > Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR.

---NOTE---
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 72 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two or more pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with any RCS cold leg temperatures ≤ LTOP arming temperature specified in the PTLR.	6 hours 24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Safety Depressurization Valves (SDVs)

LCO 3.4.11 Two SDVs and associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each SDV and each block valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SDVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One SDV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	<u>AND</u>	
	B.2 Remove power from associated block valve.	1 hour
	<u>AND</u>	
	B.3.1 Restore SDV to OPERABLE status.	72 hours
	[<u>OR</u>	
	B.3.2 Apply the requirements of Specification 5.5.18.	72 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	--------------------NOTE------------------- Required Action C.1 does not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. --- C.1 Restore block valve to OPERABLE status. [OR C.2 Apply the requirements of Specification 5.5.18.	 72 hours 72 hour]
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours
E. Two SDVs inoperable and not capable of being manually cycled.	E.1 Close associated block valves. AND E.2 Remove power from associated block valves. AND E.3 Be in MODE 3. AND E.4 Be in MODE 4.	1 hour 1 hour 6 hours 12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. More than one block valve inoperable.	F.1 Restore one block valve to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3. <u>AND</u> G.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	-----------------------------NOTE-------------------------- Not required to be performed with block valve closed in accordance with the Required Actions of this LCO. --- Perform a complete cycle of each block valve.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.11.2	Perform a complete cycle of each SDV.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with a maximum of two Safety Injection (SI) pumps and one charging pump capable of injecting into the RCS and the accumulators isolated and one of the following pressure relief capabilities:

a. Two residual heat removal (RHR) suction relief valves with setpoints specified in the PTLR ≥ 456 psig and ≤ 484 psig, or

b. The RCS depressurized and an RCS vent of ≥ 4.7 square inches.

---NOTES---

1. Two charging pumps may be made capable of injecting for ≤ 1 hour for pump swap operations.

2. Accumulator may be unisolated when accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4 when any RCS cold leg temperature is ≤ LTOP arming temperature specified in the PTLR,
MODE 5,
MODE 6 when the reactor vessel head is on.

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable when entering MODE 4.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Three or more SI pumps capable of injecting into the RCS.	A.1 Initiate action to verify a maximum of two SI pumps are capable of injecting into the RCS.	Immediately
B. Two or more charging pumps capable of injecting into the RCS.	B.1 Initiate action to verify a maximum of one charging pump is capable of injecting into the RCS.	Immediately
C. An accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	C.1 Isolate affected accumulator.	1 hour
D. Required Action and associated Completion Time of Condition C not met.	D.1 Increase RCS cold leg temperature to > LTOP arming temperature specified in the PTLR.	12 hours
	<u>OR</u>	
	D.2 Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One required RHR suction relief valve inoperable in MODE 4, 5, 6.	E.1 Restore required RHR suction relief valve to OPERABLE status. <u>OR</u> E.2 Depressurize RCS and establish RCS vent of ≥ 4.7 square inches.	12 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	Verify a maximum of two SI pumps are capable of injecting into the RCS.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.12.2	Verify a maximum of one charging pump is capable of injecting into the RCS.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.3	Verify each accumulator is isolated.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.12.4	Verify RHR suction valve is open for each required RHR suction relief valve.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.12.5	-------------------------------NOTE-------------------------- Only required to be performed when complying with LCO 3.4.12.b. --- Verify required RCS vent ≥ 4.7 square inches open.	[12 hours for unlocked open vent valve(s) AND 31 days for other vent path(s) OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.6	Verify RHR suction relief valves lift setting.	In accordance with the Inservice Testing Program
SR 3.4.12.7	Verify associated RHR suction isolation valve is locked open with operator power removed for each required RHR suction relief valve.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE,

b. 0.5 gpm unidentified LEAKAGE,

c. 10 gpm identified LEAKAGE, and

d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Pressure boundary LEAKAGE exists. <u>OR</u> Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	----------------------------NOTES-------------------------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. --- Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance.	[72 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.13.2	-----------------------------NOTE--------------------------- Not required to be performed until 12 hours after establishment of steady state operation. --- Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.	[72 hours OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, except valves in the residual heat removal (RHR) flow path when in, or during the transition to or from, the RHR mode of operation.

ACTIONS

--NOTES--

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	--------------------NOTE------------------- Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 and be in the reactor coolant pressure boundary or the high pressure portion of the system. --	
	A.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2 Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours
C. RHR suction valve interlock function inoperable	C.1 Isolate the affected penetration by use of one closed manual or deactivated automatic valve	4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.14.1	---------------------------NOTES-------------------------- 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. --- Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	 In accordance with the Inservice Testing Program, and [24 months OR In accordance with the Surveillance Frequency Control Program] <u>AND</u> Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months <u>AND</u> Within 24 hours following valve actuation due to automatic or manual action or flow through the valve

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	-----------------------------NOTE---------------------------- Not required to be met when the RHR System suction valve interlock is disabled in accordance with SR 3.4.12.7. -- Verify RHR System suction valve interlock prevents the valves from being opened with a simulated or actual RCS pressure signal ≥ 425 psig.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One containment sump (level) monitor,

b. One containment atmosphere radioactivity monitor (particulate), and

c. One containment air cooler condensate flow rate monitor.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required containment sump monitor inoperable.	A.1 --------------NOTE-------------- Not required until 12 hours after establishment of steady state operation. ------------------------------------- Perform SR 3.4.13.1. AND A.2 Restore required containment sump monitor to OPERABLE status.	 Once per 24 hours 30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere radioactivity monitor inoperable.	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 --------------NOTE-------------- Not required until 12 hours after establishment of steady state operation. -------------------------------------	
	Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status.	30 days
	<u>OR</u>	
	B.2.2 Verify containment air cooler condensate flow rate monitor is OPERABLE.	30 days
C. Required containment air cooler condensate flow rate monitor inoperable.	C.1 Perform SR 3.4.15.1.	Once per 8 hours
	<u>OR</u>	
	C.2 --------------NOTE-------------- Not required until 12 hours after establishment of steady state operation. -------------------------------------	
	Perform SR 3.4.13.1.	Once per 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required containment atmosphere radioactivity monitor inoperable. <u>AND</u> Required containment air cooler condensate flow rate monitor inoperable.	D.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status. <u>OR</u> D.2 Restore required containment air cooler condensate flow rate monitor to OPERABLE status.	30 days 30 days
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 5.	6 hours 36 hours
F. All required monitors inoperable.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.15.2	Perform COT of the required containment atmosphere radioactivity monitor.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment sump monitor.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.15.5	Perform CHANNEL CALIBRATION of the required containment air cooler condensate flow rate monitor.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 RCS DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 specific activity shall be within limits.

APPLICABILITY: MODES 1, 2, 3 and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 not within limit.	--------------------NOTE------------------- LCO 3.0.4.c is applicable. ---	
	A.1 Verify DOSE EQUIVALENT I-131 < 60 μCi/gm.	Once per 4 hours
	AND	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. DOSE EQUIVALENT XE-133 not within limit.	--------------------NOTE------------------- LCO 3.0.4.c is applicable. ---	48 hours
	B.1 Restore DOSE EQUIVALENT XE-133 to within limit.	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. <u>OR</u> DOSE EQUIVALENT I-131 > 60 μCi/gm.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	-----------------------------NOTE---------------------------- Only required to be performed in MODE 1. --- Verify reactor coolant DOSE EQUIVALENT XE-133 specific activity ≤ 300 μCi/gm.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.4.16.2	-----------------------------NOTE---------------------------- Only required to be performed in MODE 1. --- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 1.0 μCi/gm.	[14 days OR In accordance with the Surveillance Frequency Control Program] <u>AND</u> Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	<u>AND</u>	
	A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.18 RCS Loops – Test Exceptions

LCO 3.4.18 The requirements of LCO 3.4.4, "RCS Loops - MODES 1 and 2," may be suspended with THERMAL POWER < P-7.

APPLICABILITY: MODES 1 and 2 during startup and PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. THERMAL POWER ≥ P-7.	A.1 Open reactor trip breakers.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.18.1	Verify THERMAL POWER is < P-7.	1 hour
SR 3.4.18.2	Perform a COT for each power range neutron flux - low channel, intermediate range neutron flux channel, P-10, and P-13.	Prior to initiation of startup and PHYSICS TESTS
SR 3.4.18.3	Perform an ACTUATION LOGIC TEST on P-7.	Prior to initiation of startup and PHYSICS TESTS

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Four ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS pressure > 1000 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits.	A.1 Restore boron concentration to within limits. [<u>OR</u> A.2 Apply the requirements of Specification 5.5.18.	72 hours 72 hours]
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status. [<u>OR</u> B.2 Apply the requirements of Specification 5.5.18.	24 hours 24 hours]
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Reduce RCS pressure to ≤ 1000 psig.	6 hours 12 hours
D. Two or more accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 19,338 gallons and ≤ 19,734 gallons.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 586psig and ≤ 695 psig.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 4000 ppm and ≤ 4200 ppm.	[31 days OR In accordance with the Surveillance Frequency Control Program] <u>AND</u> --------NOTE-------- Only required to be performed for affected accumulators ------------------------ Once within 6 hours after each solution volume increase of ≥ 190 gallons that is not the result of addition from the refueling water storage pit
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when RCS pressure is ≥ 1920 psig.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.1.6	Verify isotopic concentration of B-10 in each accumulator is ≥ 19.9% (atom percent).	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 Safety Injection System (SIS) - Operating

LCO 3.5.2 Three SIS trains shall be OPERABLE.

---NOTES--

1. In MODE 3, all safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. In MODE 3, SI pumps may be made incapable of injecting to support transition into or from the Applicability of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for up to 4 hours or until the temperature of all RCS cold legs exceeds Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR plus 25°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required train inoperable.	A.1 Restore three trains to OPERABLE status. [OR A.2 Apply the requirements of Specification 5.5.18.	72 hours 72 hours]
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position (with power to the valve operator removed).		[12 hours OR In accordance with the Surveillance Frequency Control Program]
<u>Number</u>	<u>Function</u>	<u>Position</u>	
SIS-AOV -201B and C	Accumulator Makeup	CLOSED	
SIS-MOV -024A,B,C and D	Safety Injection Pump Full-Flow Test Line Stop	CLOSED	
SR 3.5.2.2	-------------------------- NOTE--------------------------- Not required to be met for system vent flow paths opened under administrative control. --- Verify each SIS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.		[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.2.3	Verify each SI pump's developed head at the test flow point is greater than or equal to the required developed head.		In accordance with the Inservice Testing Program
SR 3.5.2.4	Verify each ECCS valve manually activated during a design basis accident event in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position.		In accordance with the Inservice Testing Program
SR 3.5.2.5	Verify each SI pump starts automatically on an actual or simulated actuation signal.		[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.6	Verify by visual inspection, each SIS train ECC/CS STRAINER is not restricted by debris and shows no evidence of structural distress or abnormal corrosion.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.2.7	Verify ECCS locations susceptible to gas accumulation are sufficiently filled with water.	[31 days <u>OR</u> In accordance with the Surveillance Frequency Control Program]

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 Safety Injection System (SIS) - Shutdown

LCO 3.5.3 Two SIS trains shall be OPERABLE.

APPLICABILITY: MODE 4.

ACTIONS

--NOTE--
LCO 3.0.4.b is not applicable to SI pumps.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required SIS train inoperable.	A.1 Restore required SIS train to OPERABLE status.	1 hour
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	The following SRs are applicable for all equipment required to be OPERABLE: SR 3.5.2.1 SR 3.5.2.3 SR 3.5.2.5	In accordance with applicable SRs

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Pit (RWSP)

LCO 3.5.4 The RWSP shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RWSP boron concentration not within limits. OR RWSP borated water temperature not within limits.	A.1 Restore RWSP to OPERABLE status. [OR A.2 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ------------------------------------ Apply the requirements of Specification 5.5.18.	8 hours 8 hours]
B. RWSP inoperable for reasons other than Condition A.	B.1 Restore RWSP to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	-------------------------------NOTE------------------------- Only required to be performed when containment air temperature is < 32°F or >120°F. -- Verify RWSP borated water temperature is ≥ 32°F and ≤ 120°F.	[24 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.4.2	Verify RWSP borated water volume is ≥ 79,920 ft^3 (597,800 gallons).	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.4.3	Verify RWSP boron concentration is ≥ 4000 ppm and ≤ 4200 ppm.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.4.4	Verify isotopic concentration of B-10 in the RWSP is ≥ 19.9% (atom percent).	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.5 pH Adjustment

LCO 3.5.5 The pH adjustment baskets shall contain ≥ 44,100 pounds of sodium tetraborate decahydrate (NaTB).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The mass of NaTB not within limit.	A.1 Restore mass of NaTB to within limit.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	Verify that the NaTB pH adjustment baskets contain at least 44,100 pounds of NaTB.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.5.5.2	Verify that a sample from the NaTB pH adjustment baskets provides adequate pH adjustment of the post-accident water.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.1.2	Verify containment structural integrity in accordance with the Containment Tendon Surveillance Program.	In accordance with the Containment Tendon Surveillance Program

3.6 CONTAINMENT SYSTEMS

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

---NOTES---

1. Entry and exit is permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	--------------------NOTES----------------- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. --	
	A.1 Verify the OPERABLE door is closed in the affected air lock. <u>AND</u>	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.1 Lock the OPERABLE door closed in the affected air lock. [OR A.2.2 --------------NOTE-------------- This Required Action is not applicable in MODE 4. ------------------------------------- Apply the requirements of Specification 5.5.18. <u>AND</u> A.3 --------------NOTE-------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ------------------------------------- Verify the OPERABLE door is locked closed in the affected air lock.	24 hours 24 hours] Once per 31 days
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	-------------------NOTES------------------ 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. --- B.1 Verify an OPERABLE door is closed in the affected air lock. <u>AND</u>	 1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.2.1 Lock an OPERABLE door closed in the affected air lock.	24 hours
	[OR	
	B.2.2 --------------NOTE-------------- This Required Action is not applicable in MODE 4. -------------------------------------	
	Apply the requirements of Specification 5.5.18.	24 hours]
	<u>AND</u>	
	B.3 --------------NOTE-------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. -------------------------------------	Once per 31 days
	Verify an OPERABLE door is locked closed in the affected air lock.	
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	C.3.1 Restore air lock to OPERABLE status.	24 hours
	[OR	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	C.3.2 --------------NOTE-------------- This Required Action is not applicable in MODE 4. ------------------------------------- Apply the requirements of Specification 5.5.18.	24 hours]
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	----------------------------NOTES--------------------------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. ---	
	Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.2.2	Verify only one door in the air lock can be opened at a time.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

--NOTES--

1. Penetration flow path(s), except for 36 inch high volume purge valve flow paths, may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----------NOTE----------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------- One or more penetration flow paths with one containment isolation valve inoperable for reasons other than Condition D.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2 -------------NOTES------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -----------NOTE----------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------- One or more penetration flow paths with two containment isolation valves inoperable for reasons other than Condition D.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. -----------NOTE----------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ------------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. [<u>OR</u> C.1.2 --------------NOTE-------------- This Required Action is not applicable in MODE 4. ----------------------------------- Apply the requirements of Specification 5.5.18. <u>AND</u>	72 hours 72 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	C.2 -------------NOTES------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more penetration flow paths with one or more high volume purge valves not within purge valve leakage limits.	D.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	24 hours
	<u>AND</u>	
	D.2 -------------NOTES------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment
	<u>AND</u>	
	D.3 Perform SR 3.6.3.6 for the resilient seal purge valves closed to comply with Required Action D.1.	Once per 92 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each 36 inch high volume purge valve is sealed closed, except for one high volume purge valve in a penetration flow path while in Condition D of this LCO.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.6.3.2	Verify each 8 inch low volume purge valve is closed, except when the 8 inch containment low volume purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.	[31 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.3	----------------------------NOTE--------------------------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.6.3.4	----------------------------NOTE--------------------------- Valves and blind flanges in high radiation areas may be verified by use of administrative means. --- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days
SR 3.6.3.5	Verify the isolation time of each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.6	Perform leakage rate testing for 36 inch high volume purge valves with resilient seals.	[184 days OR In accordance with the Surveillance Frequency Control Program] AND Within 92 days after opening the valve
SR 3.6.3.7	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ -0.3 psig and ≤ +2.0 psig.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 120 °F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment average air temperature is within limit.	[24 hours OR In accordance with the Surveillance Frequency Control Program]

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Three containment spray (CS) trains shall be OPERABLE.

---NOTE---
CS train may be considered OPERABLE during alignment and operation for decay heat removal as RHRS if capable of being manually realigned to the CS mode of operation.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required containment spray train inoperable.	A.1 Restore three containment spray trains to OPERABLE status. [<u>OR</u> A.2 -------------NOTE--------------- This Required Action is not applicable in MODE 4. ------------------------------------ Apply the requirements of Specification 5.5.18	72 hours 72 hours]
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.6.6.2	Verify each CS/RHR pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.3	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.6.6.4	Verify each CS/RHR pump starts automatically on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.5	Verify each spray nozzle is unobstructed.	At first refueling <u>AND</u> [10 years OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 Six MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more steam generators with one or more MSSVs inoperable.	A.1 Reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	4 hours
	<u>AND</u>	
	A.2 --------------NOTE-------------- Only required in MODE 1. ------------------------------------ Reduce the Power Range Neutron Flux - High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met. OR One or more steam generators with ≥ 5 MSSVs per steam generator inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	----------------------------NOTE--------------------------- Only required to be performed in MODES 1 and 2. --- Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
5	59
4	45
3	31
2	18

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER				LIFT SETTING (psig ± 1%)
STEAM GENERATOR				
#1	#2	#3	#4	
MSS-SRV-509A	MSS-SRV-509B	MSS-SRV-509C	MSS-SRV-509D	1185
MSS-SRV-510A	MSS-SRV-510B	MSS-SRV-510C	MSS-SRV-510D	1215
MSS-SRV-511A	MSS-SRV-511B	MSS-SRV-511C	MSS-SRV-511D	1244
MSS-SRV-512A	MSS-SRV-512B	MSS-SRV-512C	MSS-SRV-512D	1244
MSS-SRV-513A	MSS-SRV-513B	MSS-SRV-513C	MSS-SRV-513D	1244
MSS-SRV-514A	MSS-SRV-514B	MSS-SRV-514C	MSS-SRV-514D	1244

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status. [OR A.2 Apply the requirements of Specification 5.5.18.	8 hours 8 hours]
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. -----------NOTE----------- Separate Condition entry is allowed for each MSIV. ------------------------------ One or more MSIVs inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	-----------------------------NOTE--------------------------- Only required to be performed in MODES 1 and 2. --- Verify the isolation time of each MSIV is ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.7.2.2	-----------------------------NOTE--------------------------- Only required to be performed in MODES 1 and 2. --- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Regulation Valves (MFRVs), Main Feedwater Bypass Regulation Valves (MFBRVs), and Steam Generator Water Filling Control Valves (SGWFCVs)

LCO 3.7.3 Four MFIVs, four MFRVs, four MFBRVs, and four SGWFCVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when MFIVs, MFRVs, MFBRVs, or SGWFCVs are closed.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more MFIVs inoperable.	A.1 Close or isolate MFIV. <u>AND</u> A.2 Verify MFIV is closed or isolated.	72 hours Once per 7 days
B. One or more MFRVs inoperable.	B.1 Close or isolate MFRV. <u>AND</u> B.2 Verify MFRV is closed or isolated.	72 hours Once per 7 days
C. One or more MFBRVs inoperable.	C.1 Close or isolate MFBRV. <u>AND</u> C.2 Verify MFBRV is closed or isolated.	72 hours Once per 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more SGWFCVs inoperable.	D.1 Close or isolate SGWFCV. <u>AND</u> D.2 Verify SGWFCV is closed or isolated.	72 hours Once per 7 days
E. Two valves in the same flow path inoperable.	E.1 Isolate affected flow path.	8 hours
F. Required Action and associated Completion Time not met.	F.1 Be in MODE 3. <u>AND</u> F.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify the isolation time of each MFIV, MFRV, MFBRV, and SGWFCV is ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.7.3.2	Verify each MFIV, MFRV, MFBRV, and SGWFCV actuates to the isolation position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.4 Main Steam Depressurization Valves (MSDVs)

LCO 3.7.4 Four MSDV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required MSDV line inoperable.	A.1 Restore required MSDV line to OPERABLE status. [OR A.2 Apply the requirements of Specification 5.5.18.	7 days 7 days]
B. Two or more required MSDV lines inoperable.	B.1 Restore all but one MSDV line to OPERABLE status. [OR B.2 Apply the requirements of Specification 5.5.18.	24 hours 24 hours]
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each MSDV.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.4.2	Verify one complete cycle of each MSDV block valve.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.5 Emergency Feedwater System (EFWS)

LCO 3.7.5 Four EFW trains shall be OPERABLE with all EFW pump discharge cross-connect line isolation valves in all trains closed.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable when entering MODE 1.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to one turbine driven EFW pump inoperable. <u>OR</u> -----------NOTE----------- Only applicable if MODE 2 has not been entered following refueling. ------------------------------- One turbine driven EFW pump inoperable in MODE 3 following refueling.	A.1 Restore affected equipment to OPERABLE status. <u>OR</u> --------------NOTE-------------- When the EFW pump discharge cross-connect line isolation valves are closed. ------------------------------------ A.2 Open all EFW pump discharge cross-connect line isolation valves.	7 days 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One EFW train inoperable in MODE 1, 2, or 3 for reasons other than Condition A.	B.1 Restore EFW train to OPERABLE status. <u>OR</u> --------------NOTE-------------- When the EFW pump discharge cross-connect line isolation valves are closed. ------------------------------------ B.2 Open all EFW pump discharge cross-connect line isolation valves.	72 hours 72 hours
C. Required Action and associated Completion Time for Condition A or B not met. <u>OR</u> Two EFW trains inoperable in MODE 1, 2, or 3.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours
D. Three EFW trains inoperable in MODE 1, 2, or 3.	D.1 --------------NOTE-------------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one additional EFW train is restored to OPERABLE status. ------------------------------------ Initiate action to restore one additional EFW train to OPERABLE status.	 Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	----------------------------NOTE--------------------------- EFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the EFW mode of operation. --- Verify each EFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.5.2	----------------------------NOTE--------------------------- Not required to be performed for the turbine driven EFW pump until 24 hours after ≥ 1000 psig in the steam generator. --- Verify the developed head of each EFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.5.3	-----------------------------NOTE---------------------------- EFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the EFW mode of operation. --- Verify each EFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.5.4	----------------------------NOTES---------------------------- 1. Not required to be performed for the turbine driven EFW pump until 24 hours after ≥ 1000 psig in the steam generator. 2. EFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the EFW mode of operation. --- Verify each EFW pump starts automatically on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.5.5	Verify proper alignment of the required EFW flow paths by verifying flow from the emergency feedwater pit to each steam generator.	Prior to entering MODE 2 whenever unit has been in MODE 5, MODE 6, or defueled for a cumulative period of > 30 days

3.7 PLANT SYSTEMS

3.7.6 Emergency Feedwater Pit (EFW Pit)

LCO 3.7.6 Two EFW Pits shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both EFW Pits inoperable.	A.1 Verify by administrative means OPERABILITY of backup water supply.	4 hours AND Once per 12 hours thereafter
	AND	
	A.2.1 Restore both EFW Pits to OPERABLE status.	7 days
	[OR	
	A.2.2 Apply the requirements of Specification 5.5.18.	7 days]
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify each EFW Pit level is ≥ 204,850 gallons.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Three CCW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required CCW train inoperable.	A.1 --------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. ------------------------------------- Restore three CCW trains to OPERABLE status.	 72 hours
	[OR	
	A.2 -------------NOTE--------------- This Required Action is not applicable in MODE 4. ------------------------------------ Apply the requirements of Specification 5.5.18.	 72 hours]
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	----------------------------NOTE--------------------------- Isolation of CCW flow to individual components does not render the CCW System inoperable. --- Verify each CCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.7.2	Verify train leakage for each CCW train is less than 3 gallons per hour.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.7.3	Verify total subsystem leakage for CCW valving used to isolate non-safety piping is less than 25 gallons per 7 days.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.7.4	Verify each CCW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.7.5	Verify each CCW pump starts automatically on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.8 Essential Service Water System (ESWS)

LCO 3.7.8 Three ESWS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ESWS train inoperable.	A.1 --------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by ESWS. ------------------------------------- Restore three ESWS trains to OPERABLE status.	72 hours
	[OR	
	A.2 -------------NOTE------------- This Required Action is not applicable in MODE 4. ------------------------------------ Apply the requirements of Specification 5.5.18.	72 hours]
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	----------------------------NOTE--------------------------- Isolation of ESWS flow to individual components does not render the ESWS inoperable. --- Verify each ESWS manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.8.2	Verify each ESWS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal. The motor operated valve provided at the discharge of each pump opens automatically after starting the ESW pump. This interlock prevents the pump from starting if the valve is not closed. The closed discharge valve opens after starting the ESWP.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.8.3	Verify each ESWS pump starts automatically on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.9 Ultimate Heat Sink (UHS)

LCO 3.7.9 [[Three]] UHS [[cooling towers]] shall be OPERABLE [[including their associated fans and three OPERABLE transfer pumps.]]

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. [[One required cooling tower with associated cooling tower fans inoperable.]]	A.1 [[Restore three cooling towers with associated fans to OPERABLE status.]] [[OR A.2 -------------NOTE------------- This Required Action is not applicable in MODE 4. ------------------------------------ Apply the requirements of Specification 5.5.18.	[[72 hours]] 72 hours]]
B. [[One or more required]] UHS [[basins]] with water temperature not within limits.	B.1 Verify that water temperature of the UHS is [[≤93°F]] averaged over the previous 24 hour period.	Once per hour
C. One or more required UHS [[basins]] with water level not within limits.	C.1 Restore water level(s) to within limits.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. [[One or more required UHS transfer pump(s) inoperable.]]	D.1 [[Restore the transfer pump(s) to OPERABLE status.]] [[OR D.2.1 Implement an alternate method of basin transfer.]] [[AND D.2.2 Restore the transfer pump(s) to OPERABLE status]]	[[7 days]] [[7 days]] [[31 days]]
E. Required Action and associated Completion Time of Condition [[A, B, C, or D]] not met. [[OR UHS inoperable for reasons other than Condition A, B, C, or D.]]	E.1 Be in MODE 3. AND E.1 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Verify [[each]] required UHS [[basin]] water inventory is [[≥ 2,850,000 gallons]].	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.2	Verify water temperature of UHS is [[≤ 93°F]].	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.9.3	[[Operate each cooling tower fan for ≥ 15 minutes.]]	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.4	[[Verify each cooling tower fan starts automatically on an actual or simulated actuation signal.]]	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.5	[[Verify each UHS transfer pump starts on manual actuation.]]	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.6	Verify each UHS manual, power-operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.9.7	Verify each UHS automatic valve and each control valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.10 Main Control Room HVAC System (MCRVS)

---NOTE---
The MCRVS consists of two trains of main control room emergency filtration system (MCREFS) and four trains of main control room air temperature control system (MCRATCS).

LCO 3.7.10 The MCRVS shall be OPERABLE with:

a. Two MCREFS trains OPERABLE, and

b. Three MCRATCS trains OPERABLE.

---NOTE---
The control room envelope (CRE) boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, 3 and 4,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required MCREFS train inoperable.	A.1 Restore MCREFS train to OPERABLE status.	7 days
B. One required MCRATCS trains inoperable.	B.1 Restore three MCRATCS trains to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required MCRVS inoperable due to inoperable CRE boundary in MODE 1, 2, 3, or 4.	C.1 Initiate action to implement mitigating actions.	Immediately
	<u>AND</u>	
	C.2 Verify mitigating actions to ensure CRE occupant exposures to radiological, chemical, and smoke hazards will not exceed limits.	24 hours
	<u>AND</u>	
	C.3 Restore CRE boundary to OPERABLE status.	90 days
D. Required Action and associated Completion Time of Condition A, B, or C not met in MODE 1, 2, 3, or 4.	D.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	D.2 Be in MODE 5.	36 hours
E. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies.	E.1 --------------NOTE--------------- [Place in toxic gas protection mode if automatic transfer to toxic gas protection mode is inoperable.] ------------------------------------- Place OPERABLE MCRVS trains in emergency mode.	Immediately
	<u>OR</u>	
	E.2 Suspend movement of irradiated fuel assemblies.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required MCRVS inoperable during movement of irradiated fuel assemblies. <u>OR</u> Required MCRVS inoperable due to inoperable CRE boundary during movement of irradiated fuel assemblies.	F.1 Suspend movement of irradiated fuel assemblies.	Immediately
G. Required MCRVS inoperable in MODE 1, 2, 3, or 4 for reasons other than Condition C.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Operate each MCREFS train for ≥ 10 continuous hours with the heaters operating.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.10.2	Perform required MCREFS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.10.3	Verify each MCRVS train actuates on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.10.4	Perform required CRE unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.	In accordance with the Control Room Envelope Habitability Program
SR 3.7.10.5	Verify two MCRATCS trains have the capacity to remove the design heat load.	[24 months on a STAGGERED TEST BASIS OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.11 Annulus Emergency Exhaust System

LCO 3.7.11 Two Annulus Emergency Exhaust System trains shall be OPERABLE.

--NOTE--
The associated room boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Annulus Emergency Exhaust System train inoperable.	A.1 Restore Annulus Emergency Exhaust System train to OPERABLE status.	7 days
B. Two Annulus Emergency Exhaust System trains inoperable due to inoperable associated room boundary.	B.1 Restore associated room boundary to OPERABLE status.	24 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Operate each Annulus Emergency Exhaust System train for ≥ 15 minutes.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.11.2	Perform required Annulus Emergency Exhaust System filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.11.3	Verify each Annulus Emergency Exhaust System train actuates on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.7.11.4	Verify the associated room can be maintained at a pressure ≤ -0.25 inches water gauge relative to surrounding areas using one Annulus Emergency Exhaust System train during the accident condition at a flow rate of ≤ 5600 cfm within 240 seconds after a start signal.	[24 months on a STAGGERED TEST BASIS OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.12 Spent Fuel Pit Water Level

LCO 3.7.12 The spent fuel pit water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent Fuel pit water level not within limit.	A.1 --------------NOTE-------------- LCO 3.0.3 is not applicable. ------------------------------------- Suspend movement of irradiated fuel assemblies in the spent fuel pit.	 Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.12.1	Verify the spent fuel pit water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	At the start of any spent fuel movement campaign AND [7 days OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.13 Spent Fuel Pit Boron Concentration

LCO 3.7.13 The spent fuel pit boron concentration shall be ≥ 4000 ppm.

APPLICABILITY: When fuel assemblies are stored in the spent fuel pit and a spent fuel pit verification has not been performed since the last movement of fuel assemblies in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent fuel pit boron concentration not within limit.	--------------------NOTE------------------- LCO 3.0.3 is not applicable. ---	
	A.1 Suspend movement of fuel assemblies in the spent fuel pit.	Immediately
	<u>AND</u>	
	A.2.1 Initiate action to restore spent fuel pit boron concentration to within limit.	Immediately
	<u>OR</u>	
	A.2.2 Initiate action to perform a spent fuel pit verification.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.13.1	Verify the spent fuel pit boron concentration is within limit.	[7 days OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.14 Secondary Specific Activity

LCO 3.7.14 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. <u>AND</u> A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.14.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.7 PLANT SYSTEMS

3.7.15 Main Steam Line Leakage

LCO 3.7.15 Main steam line leakage through the pipe walls inside containment shall be limited to 0.5gpm.

APPLICABILITY: MODES 1, 2, 3and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Main steam line leakage exceeds Operational limit.	A.1 Be in MODE 3. <u>AND</u> A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.15.1	Verify main steam line leakage into the containment Sump ≤ 0.5 gpm	[72 hours OR In accordance with the Surveillance Frequency Control Program]

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following ac electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E ac electrical power distribution system,

b. Three Class 1E Gas Turbine Generators (GTGs) capable of supplying the onsite Class 1E power distribution subsystem(s), and

c. The associated automatic load sequencers for each required Class 1E GTG shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable to Class 1E GTGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	A.2 Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	A.3.1 Restore required offsite circuit to OPERABLE status. [OR	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.3.2 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ----------------------------------- Apply the requirements of Specification 5.5.18.	72 hours]
B. One required Class 1E GTG inoperable.	B.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	B.2 Declare required feature(s) supported by the inoperable Class 1E GTGs inoperable when its required redundant feature in a train with an OPERABLE Class 1E GTG is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE Class 1E GTGs are not inoperable due to common cause failure. OR	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	B.3.2 Perform SR 3.8.1.2 for OPERABLE Class 1E GTGs.	24 hours
	AND	
	B.4.1 Restore required Class 1E GTGs in three trains to OPERABLE status.	72 hours
	[OR	
	B.4.2 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ----------------------------------- Apply the requirements of Specification 5.5.18.	72 hours]
C. Two required offsite circuits inoperable.	C.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND	
	C.2.1 Restore one required offsite circuit to OPERABLE status.	24 hours
	[OR	
	C.2.2 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ----------------------------------- Apply the requirements of Specification 5.5.18.	24 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One required Class 1E GTG inoperable.	D.1 Restore required offsite circuit to OPERABLE status. OR D.2 Restore required Class 1E GTG(s) in three trains to OPERABLE status. [OR D.3 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ---------------------------------- Apply the requirements of Specification 5.5.18.	12 hours 12 hours 12 hours]
E. Two or more required Class 1E GTGs inoperable.	E.1 Restore two required Class 1E GTGs in two trains to OPERABLE status.	2 hours
F. One required automatic load sequencer(s) inoperable.	F.1 Restore required automatic load sequencer(s) to OPERABLE status. [OR F.2 -------------NOTE-------------- This Required Action is not applicable in MODE 4. ---------------------------------- Apply the requirements of Specification 5.5.18.	12 hours 12 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours
H. Two offsite circuits and one or more required GTGs inoperable. OR One offsite circuit and two or more required GTGs inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.2	Verify each Class 1E GTG starts from standby condition and achieves: a. In ≤ 100 seconds, voltage ≥ 6762 V and frequency ≥ 59.4 Hz and b. Steady state voltage ≥ 6762 V and ≤ 7038 V, and frequency ≥ 59.4 Hz and ≤ 60.6 Hz.	[31 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	---------------------------NOTES-------------------------- 1. Class 1E GTG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one Class 1E GTG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2. --- Verify each Class 1E GTG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 4050 kW and ≤ 4500 kW.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.4	Verify each day tank contains ≥ 600 gallons of fuel oil.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	[31 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	[92 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.7	----------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify automatic and manual transfer of ac power sources from the normal offsite circuit to each alternate offsite circuit.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	---------------------------NOTES--------------------------- 1. This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with the Class 1E GTG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. --	
	Verify each Class 1E GTG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 63 Hz, b. Within 3 seconds following load rejection, the voltage is ≥ 6762 V and ≤ 7038 V, and c. Within 3 seconds following load rejection, the frequency is ≥ 59.4 Hz and ≤ 60.6 Hz.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	---------------------------NOTES-------------------------- 1. This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with Class 1E GTG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. --- Verify each Class 1E GTG does not trip and voltage is maintained ≤ 8280 V during and following a load rejection of ≥ 4050 kW and ≤ 4500 kW.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	---------------------------NOTE--------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses, b. Load shedding from emergency buses, c. Class 1E GTG auto-starts from standby condition and: 1. Energizes permanently connected loads in ≤ 100 seconds, 2. Energizes auto-connected shutdown loads through automatic load sequencer, 3. Maintains steady state voltage ≥ 6762 V and ≤ 7038 V, 4. Maintains steady state frequency ≥ 59.4 Hz and ≤ 60.6 Hz, and 5. Supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	---------------------------NOTE--------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --	
	Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each Class 1E GTG auto-starts from standby condition and: a. In ≤ 100 seconds after auto-start and during tests, achieves voltage ≥ 6762 V and frequency ≥ 59.4 Hz, b. Achieves steady state voltage ≥ 6762 V and ≤ 7038 V and frequency ≥ 59.4 Hz and ≤ 60.6 Hz, c. Operates for ≥ 5 minutes, d. Permanently connected loads remain energized from the offsite power system, and e. Emergency loads are energized or auto-connected through the automatic load sequencer from the offsite power system.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.12	---------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --	
	Verify each Class 1E GTG's noncritical automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal. a. Overspeed b. Generator differential current, and c. High exhaust gas temperature	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	---------------------------NOTES-------------------------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 3. If performed with Class 1E GTG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. ---	
	Verify each Class 1E GTG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4725 kW and ≤ 4950 kW and b. For the remaining hours of the test loaded ≥ 4050 kW and ≤ 4500 kW.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	---------------------------NOTE--------------------------- This Surveillance shall be performed within 5 minutes of shutting down the Class 1E GTG after the GTG has operated ≥ 2 hours loaded ≥ 4050 kW and ≤ 4500 kW. Momentary transients outside of load range do not invalidate this test. --- Verify each Class 1E GTG starts and achieves: a. In ≤ 100 seconds, voltage ≥ 6762 V and frequency ≥ 59.4 Hz and b. Steady state voltage ≥ 6762 V, and ≤ 7038 V and frequency ≥ 59.4 Hz and ≤ 60.6 Hz.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.15	---------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify each Class 1E GTG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power, b. Transfers loads to offsite power source, and c. Returns to ready-to-load operation.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	---------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---	
	Verify, with a Class 1E GTG operating in test mode and connected to its bus, an actual or simulated ESF actuation signal overrides the test mode by: a. Returning Class 1E GTG to ready-to-load operation and b. Automatically energizing the emergency load from offsite power.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.17	---------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---	
	Verify interval between each sequenced load block is within ± 10% of design interval for each emergency and shutdown load sequencer.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	---------------------------NOTE---------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---	
	Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses, b. Load shedding from emergency buses, and c. Class 1E GTG auto-starts from standby condition and: 1. Energizes permanently connected loads in ≤ 100 seconds, 2. Energizes auto-connected emergency loads through load sequencer, 3. Achieves steady state voltage ≥ 6762 V and ≤ 7038 V, 4. Achieves steady state frequency ≥ 59.4 Hz and ≤ 60.6 Hz, and 5. Supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	Verify when started simultaneously from standby condition, each Class 1E GTG achieves: a. In ≤ 100 seconds, voltage ≥ 6762 V and frequency ≥ 59.4 Hz and b. Steady state voltage ≥ 6762 V and ≤ 7038 V, and frequency ≥ 59.4 Hz and ≤ 60.6 Hz.	[10 years OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.1.20	Perform cleaning of fuel nozzles for each Class 1E gas turbine generator.	Once per 50 gas turbine generator starts

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources - Shutdown

LCO 3.8.2 The following ac electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E ac electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems - Shutdown" and

b. Two Class 1E Gas Turbine Generators (GTGs) capable of supplying two trains of the onsite Class 1E ac electrical power distribution subsystem(s) required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

--NOTE--

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	-------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.10, with one required train de-energized as a result of Condition A. ---	
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.2 Suspend movement of irradiated fuel assemblies. AND A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration. AND A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately Immediately Immediately
B. One or more required Class 1E GTG inoperable.	B.1 Suspend CORE ALTERATIONS. AND B.2 Suspend movement of irradiated fuel assemblies. AND B.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration. AND B.4 Initiate action to restore required Class 1E GTGs to OPERABLE status.	Immediately Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.2.1	---------------------------NOTE--------------------------- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.8 through SR 3.8.1.10, SR 3.8.1.12 through SR 3.8.1.15, and SR 3.8.1.17. -- For ac sources required to be OPERABLE, the SRs of Specification 3.8.1, "AC Sources - Operating," except SR 3.8.1.7, SR 3.8.1.11, SR 3.8.1.16, SR 3.8.1.18, and SR 3.8.1.19, are applicable.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Class 1E Gas Turbine Generator Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored gas turbine fuel oil, lube oil, and starting air subsystem shall be within limits for each required Class 1E Gas Turbine Generator (GTG).

APPLICABILITY: When associated Class 1E GTG is required to be OPERABLE.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Class 1E GTG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Class 1E GTGs with fuel level < 91,000 gallons and > 78,000 gallons in storage tank.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more Class 1E GTGs with lube oil inventory < 81 gallons and > 79 gallons.	B.1 Restore lube oil inventory to within limits.	48 hours
C. One or more Class 1E GTGs with stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates to within limits.	7 days
D. One or more Class 1E GTGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more Class 1E GTGs with starting air receiver pressure < 398 psig and ≥ 228 psig.	E.1 Restore starting air receiver pressure to ≥ 270 psig.	48 hours
F. Required Action and associated Completion Time not met. <u>OR</u> One or more Class 1E GTGs with gas turbine fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C, D, or E.	F.1 Declare associated Class 1E GTG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ 91,000 gallons of fuel.	[31 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.3.2	Verify lubricating oil inventory is ≥ 81 gallons.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the GTG Fuel Oil Testing Program.	In accordance with the GTG Fuel Oil Testing Program
SR 3.8.3.4	Verify each Class 1E GT/G air start receiver pressure is ≥ 398 psig.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources - Operating

LCO 3.8.4 DC electrical power subsystems in three trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required battery charger inoperable.	A.1 Restore battery terminal voltages in three trains to greater than or equal to the minimum established float voltage.	2 hours
	<u>AND</u>	
	A.2 Verify battery float current ≤ [5] amps.	Once per 24 hours
	<u>AND</u>	
	A.3.1 Restore battery chargers to OPERABLE status.	7 days
	[OR	
	A.3.2 --------------NOTE------------- This Required Action is not applicable in MODE 4. ---------------------------------- Apply the requirements of Specification 5.5.18.	7 days]
B. One required battery inoperable.	B.1 Restore batteries in three trains to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One of the required three dc electrical power subsystems inoperable for reasons other than Condition A or B.	C.1 Restore dc electrical power subsystems in three trains to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.4.2	Verify each battery charger supplies ≥ 700 amps at greater than or equal to the minimum established float voltage for ≥ 8 hours. OR Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	[24 months OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.3	---------------------------NOTES-------------------------- 1. The modified performance discharge test in SR 3.8.6.6 may be performed in lieu of SR 3.8.4.3. 2. This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources - Shutdown

LCO 3.8.5 DC electrical power subsystems shall be OPERABLE to support the dc electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems - Shutdown".

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

---NOTE---

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One battery charger on one required train inoperable. <u>AND</u> The required redundant train(s) battery and charger OPERABLE.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	<u>AND</u>	
	A.2 Verify battery float current ≤ [5] amps.	Once per 24 hours
	<u>AND</u>	
	A.3 Restore battery charger to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more required dc electrical power subsystems inoperable for reasons other than Condition A. OR Required Actions and associated Completion Time of Condition A not met.	B.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	B.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	B.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	B.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	B.2.4 Initiate action to restore required dc electrical power subsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	-----------------------------NOTE---------------------------- The following SRs are not required to be performed: SR 3.8.4.2 and SR 3.8.4.3. -- For dc sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.2 SR 3.8.4.3	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Parameters

LCO 3.8.6 Battery parameters for Train A, B, C, and D batteries shall be within limits.

APPLICABILITY: When associated dc electrical power subsystems are required to be OPERABLE.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One battery on one required train with one or more battery cells float voltage < 2.07 V.	A.1 Perform SR 3.8.4.1.	2 hours
	AND	
	A.2 Perform SR 3.8.6.1.	2 hours
	AND	
	A.3 Restore affected cell voltage ≥ 2.07 V.	24 hours
B. One battery on one required train with float current > [5] amps.	B.1 Perform SR 3.8.4.1.	2 hours
	AND	
	B.2 Restore battery float current to ≤ [5] amps.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
---------------NOTE-------------- Required Action C.2 shall be completed if electrolyte level was below the top of plates. -------------------------------------	-------------------NOTE-------------------- Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. ---	
C. One battery on one required train with one or more cells electrolyte level less than minimum established design limits.	C.1 Restore electrolyte level to above top of plates.	8 hours
	<u>AND</u>	
	C.2 Verify no evidence of leakage.	12 hours
	<u>AND</u>	
	C.3 Restore electrolyte level to greater than or equal to minimum established design limits.	31 days
D. One battery on one required train with pilot cell electrolyte temperature less than minimum established design limits.	D.1 Restore battery pilot cell temperature to greater than or equal to minimum established design limits.	12 hours
E. One or more batteries in redundant trains with battery parameters not within limits.	E.1 Restore battery parameters for batteries in one train to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. <u>OR</u> One battery on one required train with one or more battery cells float voltage < 2.07 V and float current > [5] amps.	F.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	-----------------------------NOTE--------------------------- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. --- Verify each battery float current is ≤ [5] amps.	[7 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.2	Verify each battery pilot cell voltage is ≥ 2.07 V.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.6.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.6.4	Verify each battery pilot cell temperature is greater than or equal to minimum established design limits.	[31 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.8.6.5	Verify each battery connected cell voltage is ≥ 2.07 V.	[92 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.6	-----------------------------NOTE---------------------------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	[60 months OR In accordance with the Surveillance Frequency Control Program] <u>AND</u> [12 months OR In accordance with the Surveillance Frequency Control Program] when battery shows degradation, or has reached 85% of the expected life with capacity < 100% of manufacturer's rating <u>AND</u> [24 months OR In accordance with the Surveillance Frequency Control Program] when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters - Operating

LCO 3.8.7 Inverters in three trains shall be OPERABLE.

--NOTE--
One inverter may be disconnected from its associated dc bus for ≤ 24 hours to perform an equalizing charge on its associated battery, provided:

a. The associated ac vital bus is energized from its Class 1E transformer, and

b. All other ac vital buses are energized from their associated OPERABLE inverters.

Train A and B or Train C and D ac vital buses shall not be supplied from Class 1E transformer concurrently.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required inverter inoperable.	A.1 --------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any ac vital bus de-energized. ------------------------------------- Restore inverter to OPERABLE status.	24 hours
	[OR	
	A.2 --------------NOTE------------- This Required Action is not applicable in MODE 4. ---------------------------------- Apply the requirements of Specification 5.5.18	24 hours]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, frequency, and alignments to required ac vital buses.	[7 days OR In accordance with the Surveillance Frequency Control Program]

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Inverters - Shutdown

LCO 3.8.8 Inverters shall be OPERABLE to support the onsite Class 1E ac vital bus electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems - Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

---NOTE---
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required inverters inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.4 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage, frequency, and alignments to required ac vital buses.	[7 days OR In accordance with the Surveillance Frequency Control Program]

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 The ac, dc, and ac vital bus electrical power distribution subsystems shall be OPERABLE as specified in Table 3.8.9-1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ac electrical power distribution subsystems inoperable.	--------------------NOTE------------------- Enter applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," for dc trains made inoperable by inoperable power distribution subsystems. ---	
	A.1 Restore required ac electrical power distribution subsystem(s) to OPERABLE status.	8 hours
	[OR	
	A.2 --------------NOTE------------- This Required Action is not applicable in MODE 4. ---------------------------------- Apply the requirements of Specification 5.5.18.	8 hours]
B. One required ac vital buses inoperable.	B.1 Restore ac vital bus subsystem(s) to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required dc electrical power distribution subsystems inoperable.	C.1 Restore required dc electrical power distribution subsystem(s) to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours
E. Two or more required electrical power distribution subsystems inoperable that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required ac, dc, and ac vital bus electrical power distribution subsystems.	[7 days OR In accordance with the Surveillance Frequency Control Program]

Table 3.8.9-1 Distribution System Operating Requirements

Distribution System	Requirements	Conditions
1. 6.9 kV Class 1E, A, B, C, and D	3	A
2. 480V Load Centers, A, B, C, and D	3	A
3. 480 V Load Centers A1 and D1	2 (2)	A
4. 480V MCCs A, B, C, and D	3	A
5. 480 V MCCs A1 and D1	2 (2)	A
6. 480V MOV MCCs	4 (1)	A
7. 120 V Vital AC Buses A, B, C, and D	4	B
8. 125 VDC Buses A, B, C, and D	3	C
9. 125 VDC Buses A1 and D1	2 (2)	C
10. 125 VDC Distribution Panels	3	C

Note

(1) For 480V MOV MCCs A and D both MCC 1 and MCC 2 are required to be OPERABLE.

(2) One of the two train buses may be removed from operation when switching from one train to another train.

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems - Shutdown

LCO 3.8.10 The necessary portions of ac, dc, and ac vital bus electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

---NOTE---

LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required ac, dc, or ac vital bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable. <u>OR</u> A.2.1 Suspend CORE ALTERATIONS. <u>AND</u> A.2.2 Suspend movement of irradiated fuel assemblies. <u>AND</u> A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration. <u>AND</u>	Immediately Immediately Immediately Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2.4 Initiate actions to restore required ac, dc, and ac vital bus electrical power distribution subsystems to OPERABLE status.	Immediately
	<u>AND</u>	
	A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required ac, dc, and ac vital bus electrical power distribution subsystems.	[7 days OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of the Reactor Coolant System, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6.

---NOTE---
Only applicable to the refueling canal and refueling cavity when connected to the RCS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2 Suspend positive reactivity additions.	Immediately
	<u>AND</u>	
	A.3 Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	[72 hours OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.2 Unborated Water Source Isolation Valves

LCO 3.9.2 Each valve used to isolate unborated water sources shall be secured in the closed position.

APPLICABILITY: MODE 6.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each unborated water source isolation valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE---------- Required Action A.3 must be completed whenever Condition A is entered. ------------------------------ One or more valves not secured in closed position.	A.1 Suspend CORE ALTERATIONS. <u>AND</u> A.2 Initiate actions to secure valve in closed position. <u>AND</u> A.3 Perform SR 3.9.1.1.	Immediately Immediately 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify each valve that isolates unborated water sources is secured in the closed position.	[31 days OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.3 Nuclear Instrumentation

LCO 3.9.3 Two source range neutron flux monitors shall be OPERABLE.

AND

One source range audible alarm and count rate circuit shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
B. Two required source range neutron flux monitors inoperable.	B.1 Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	AND	
	B.2 Perform SR 3.9.1.1.	Once per 12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required source range audible alarm and count rate circuit inoperable.	C.1 Initiate action to isolate unborated water sources.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Perform CHANNEL CHECK.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.3.2	----------------------------NOTE--------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.4 Containment Penetrations

LCO 3.9.4 The containment penetrations shall be in the following status:

a. The equipment hatch is closed and held in place by [four] bolts, or if open, capable of being closed,

b. One door in the emergency air lock is closed and one door in the personnel airlock capable of being closed, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere is either:

1. Closed by a manual or automatic isolation valve, blind flange, or equivalent or

2. Capable of being closed by an OPERABLE Containment Purge Isolation System.

--NOTE--
Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify each required containment penetration is in the required status.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.4.2	-----------------------------NOTE---------------------------- Only required for an open equipment hatch. --- Verify the capability to install the equipment hatch.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.4.3	-----------------------------NOTE---------------------------- Not required to be met for containment purge isolation valve(s) in penetrations closed to comply with LCO 3.9.4.c.1. --- Verify each required containment purge isolation valve actuates to the isolation position on an actual or simulated actuation signal.	[24 months OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

LCO 3.9.5 Two RHR loops shall be OPERABLE and in operation.

---NOTE---
The required RHR loops may be removed from operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause introduction of coolant into the Reactor Coolant System with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RHR loop requirements not met.	A.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	<u>AND</u>	
	A.2 Suspend loading irradiated fuel assemblies in the core.	Immediately
	<u>AND</u>	
	A.3 Initiate action to satisfy RHR loop requirements.	Immediately
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.4 Close equipment hatch and secure with [four] bolts. AND A.5 Close one door in each air lock. AND A.6.1 Close each penetration providing direct access from the containment atmosphere to the outside atmosphere with a manual or automatic isolation valve, blind flange, or equivalent. OR A.6.2 Verify each penetration is capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.	4 hours 4 hours 4 hours 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify two RHR loops are in operation and circulating reactor coolant at a flow rate of ≥ 2645 gpm per pump.	[12 hours OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS

SR 3.9.5.2	Verify required RHR loop locations susceptible to gas accumulation are sufficiently filled with water.	[31 days <u>OR</u> <u>In accordance with the Surveillance Frequency Control Program]</u>

3.9 REFUELING OPERATIONS

3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

LCO 3.9.6 Three RHR loops shall be OPERABLE, and two RHR loops shall be in operation, and low-pressure letdown line isolation valve shall be OPERABLE, with:

a. One OPERABLE safety injection (SI) pump, and

b. Required injection water volume from OPERABLE RWSP and refueling cavity.

---NOTES--

1. All CS/RHR pumps may be removed from operation for ≤ 15 minutes when switching from one train to another provided:

    a. The core outlet temperature is maintained > 10 degrees F below saturation temperature,

    b. No operations are permitted that would cause introduction of coolant into the Reactor Coolant System (RCS) with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1, and

    c. No draining operations to further reduce RCS water volume are permitted.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing, provided that the other RHR loops are OPERABLE and in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1 Initiate action to restore required RHR loops to OPERABLE status. <u>OR</u>	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately
B. One low-pressure letdown isolation valve inoperable.	B.1 Initiate action to restore low-pressure letdown line isolation valve to OPERABLE status.	Immediately
C. No RHR loop in operation.	C.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	<u>AND</u>	
	C.2 Initiate action to restore two RHR loops to operation.	Immediately
	<u>AND</u>	
	C.3 Close equipment hatch and secure with [four] bolts.	4 hours
	<u>AND</u>	
	C.4 Close one door in each air lock.	4 hours
	<u>AND</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	C.5.1 Close each penetrations providing direct access from the containment atmosphere to the outside atmosphere with a manual or automatic isolation valve, blind flange, or equivalent. <u>OR</u> C.5.2 Verify each penetration is capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.	4 hours 4 hours
D. No SI pump is OPERABLE. <u>OR</u> RWSP and refueling cavity water volume is not within limits. <u>OR</u> RWSP boron concentration is not within limits.	D.1 Initiate action to restore OPERABILITY of SI pump. <u>AND</u> D.2 Initiate actions to suspend activities that may cause a reduction in RCS water volume. <u>AND</u> D.3 Initiate actions to restore RWSP and refueling cavity water volume to within limits. <u>AND</u> D.4 Initiate actions to restore RWSP boron concentration to within limits.	Immediately Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify two RHR loops are in operation and circulating reactor coolant at a flow rate of ≥ 2645 gpm per pump.	[12 hours OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.2	Verify correct breaker alignment and indicated power available to the required CS/RHR pump that is not in operation.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.3	Perform a complete cycle of each low-pressure letdown line isolation valve.	[24 months OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.4	Verify RHR loop locations susceptible to gas accumulation are sufficiently filled with water.	[31 days OR In accordance with the Surveillance Frequency Control Program]

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.9.6.5	Verify the RWSP borated water volume (including water available in the refueling cavity) is ≥ 79,920 ft^3 (597,800 gallons).	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.6	Verify that the RWSP boron concentration is ≥ 4000 ppm and ≤ 4200 ppm.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.7	Verify the correct breaker alignment and indicated power is available to the required SI pump.	[7 days OR In accordance with the Surveillance Frequency Control Program]
SR 3.9.6.8	Verify that one SI pump is capable of supplying developed head at the test flow point greater than or equal to the required developed head following a manual start.	In accordance with the Inservice Testing Program

3.9 REFUELING OPERATIONS

3.9.7 Refueling Cavity Water Level

LCO 3.9.7 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	[24 hours OR In accordance with the Surveillance Frequency Control Program]

3.9 REFUELING OPERATIONS

3.9.8 Decay Time

LCO 3.9.8 The reactor shall be subcritical for ≥ 24 hours.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor subcritical < 24 hours.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.8.1	Verify that the reactor has been subcritical for≥ 24 hours by verification of the date and time of subcriticality.	Prior to movement of irradiated fuel assemblies within reactor vessel.

4.0 DESIGN FEATURES

4.1 Site Location

[Text description of site location.]

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 257 fuel assemblies. Each assembly shall consist of a matrix of fuel rods clad with NRC approved cladding material, which is a zirconium based alloy and containing an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium based alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Rod Cluster Control Assemblies

The reactor core shall contain 69 Rod Cluster Control Assemblies (RCCAs) each with 24 rods per assembly. The RCCA adsorber material shall be silver indium cadmium as approved by the NRC.

4.0 DESIGN FEATURES

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent,

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Subsection 9.1.1 of the DCD, and

c. A nominal 11.1 inch center to center distance between fuel assemblies placed in spent fuel storage racks.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent,

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Subsection 9.1.1 of the DCD,

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties as described in Subsection 9.1.1 of the DCD, and

d. A nominal 16.9 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.1.3 The containment racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent,

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Subsection 9.1.1 of the DCD, and

c. A nominal 16.9 inch center-to-center distance between fuel assemblies placed in containment racks.

4.3.2 Drainage

The spent fuel pit is designed and shall be maintained to prevent inadvertent draining of the pit below 23 ft above the top of irradiated fuel assemblies seated in the storage racks.

4.3.3 Capacity

The spent fuel pit is designed and shall be maintained with a storage capacity limited to no more than 900 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The [plant manager] shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The [plant manager] or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The [Shift Supervisor] shall be responsible for the control room command function. During any absence of the [Shift Supervisor] from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the [Shift Supervisor] from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout the highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the [FSAR/QA Plan].

b. The [plant manager] shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned when the reactor contains fuel and an additional non-licensed operator shall be assigned for the control room from which a reactor is operating in MODES 1, 2, 3, or 4.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. [A radiation protection technician] shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. The [operations manager or assistant operations manager] shall hold an SRO license.

e. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of [Regulatory Guide 1.8, Revision 2, 1987, or more recent revisions, or ANSI Standard acceptable to the NRC staff]. [The staff not covered by Regulatory Guide 1.8 shall meet or exceed the minimum qualifications of Regulations, Regulatory Guides, or ANSI Standards acceptable to NRC staff].

5.3.2 For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed Reactor Operator (RO) are those individuals who, in addition to meeting the requirements of Specification 5.3.1, perform the functions described in 10 CFR 50.54(m).

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978,

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and to NUREG-0737, Supplement 1, as stated in Generic Letter 82-33,

c. Quality assurance for effluent and environmental monitoring,

d. Fire Protection Program implementation, and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program, and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Reports required by Specification 5.6.1 and Specification 5.6.2.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1. Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   2. A determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and do not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

b. Shall become effective after the approval of the [plant manager], and

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include Containment Spray, Safety Injection, Chemical and Volume Control, Gaseous Waste Management and Sampling System. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements, and

b. Integrated leak test requirements for each system at least once per 24 months.

The provisions of SR 3.0.2 are applicable.

5.5.3 Post Accident Sampling

This program provides controls that ensure the capability to obtain and analyze reactor coolant, radioactive gases, and particulates in plant gaseous effluents and containment atmosphere samples under accident conditions. The program shall include the following:

a. Training of personnel,

b. Procedures for sampling and analysis, and

c. Provisions for maintenance of sampling and analysis equipment.

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001-20.2402,

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I,

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days,

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I,

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

   1. For noble gases: a dose rate ≤ 500 mrem/yr to the whole body and a dose rate ≤ 3000 mrem/yr to the skin, and

   2. For Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: a dose rate ≤ 1500 mrem/yr to any organ,

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I,

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I, and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track Subsection 3.9.1, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Prestressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in prestressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a, except where an alternative, exemption, or relief has been authorized by the NRC.

The provisions of SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

5.5.7 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975.

In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.5 Programs and Manuals

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as follows:

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and other normal and accelerated Frequencies specified in the Inservice Testing Program for performing inservice testing activities,

c. The provisions of SR 3.0.3 are applicable to inservice testing activities, and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the “as found” condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

    1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

    2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 150 gpd per SG.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables,

b. Identification of the procedures used to measure the values of the critical variables,

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser inleakage,

d. Procedures for the recording and management of data,

e. Procedures defining corrective actions for all off control point chemistry conditions, and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in accordance with Regulatory Guide 1.52, Revision 3, ASME N510-1989, and AG-1.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 3, and ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Main Control Room Emergency Filtration System (MCREFS)	3600 cfm
Annulus Emergency Exhaust System (AEES)	5600 cfm

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 3, and ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
MCREFS	3600 cfm

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 3, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and the relative humidity specified below.

ESF Ventilation System	Penetration	RH	Face Velocity
MCREFS	2.5%	70%	2400 fpm

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (continued)

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 3, and ASME N510-1989 at the system flowrate specified below ± 10%.

ESF Ventilation System	Delta P	Flowrate
MCREFS	6.4 in. water gage	3600 cfm
AEES	3.2 in. water gage	5600 cfm

e. Demonstrate that the heaters for each of the ESF systems dissipate the value specified below ± 10% when tested in accordance with ASME N510-1989.

ESF Ventilation System	Wattage
MCREFS	18,000 watts

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Management System, the quantity of radioactivity contained in gas storage tanks, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in SRP, Branch Technical Position (BTP) 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure". The liquid radwaste quantities shall be determined in accordance with SRP, BTP 11-6, "Postulated Radioactive Release due to Tank Failures".

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Management System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion),

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank is less than the amount that would result in a whole body exposure of ≥ 0.1 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents, and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Waste Management System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5 Programs and Manuals

5.5.13 Gas Turbine Generator Fuel Oil Testing Program

A gas turbine Generator fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

    1. An API gravity or an absolute specific gravity within limits,

    2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

    3. A clear and bright appearance with proper color or a water and sediment content within limits.

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil, and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Gas Turbine Fuel Oil Testing Program test frequencies.

5.5 Programs and Manuals

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the plant specific TS incorporated in the combined license or

2. A change to or a departure from Tier 1 or Tier 2* information in the FSAR pursuant to 10 CFR 52.98(c)(1) ;

3. A change to or a departure from Tier 2 information in the FSAR pursuant to 10 CFR 52.98(c)(1) that requires prior NRC approval ;

4. A change to site-specific information in the FSAR pursuant to 10 CFR 52.98(c)(2) that requires prior NRC approval ; or

5. Any other change to the Bases that requires prior NRC approval.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR as updated.

d. Proposed changes that meet the criteria of Specification 5.5.14b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross-train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected,

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists,

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities, and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, no concurrent loss of offsite power, or no concurrent loss of onsite class 1E GTG(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable, or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable, or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program

a. A program shall establish the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September, 1995:

   1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

   2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 59.5 psig. The containment design pressure is 68 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

d. Leakage rate acceptance criteria are:

   1. Primary containment leakage rate acceptance criterion is 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria for primary containment are < 0.60 L_a for the Type B and C tests combined and < 0.75 L_a for Type A tests. For the containment penetration areas, the acceptance criterion is <0.50 L_a for Type C tests.

   2. Air lock testing acceptance criteria are:

      a) Overall air lock leakage rate is≤ 0.05 L_a when tested at ≥ P_a.

      b) For each door, leakage rate is ≤ 0.01 L_a when pressurized to ≥ 10 psig.

e. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

f. Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10 CFR 50, Appendix J.

5.5 Programs and Manuals

5.5.17 Battery Monitoring and Maintenance Program

This Program provides for battery restoration and maintenance, based on the recommendations of IEEE Standard 450-2002, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," or of the battery manufacturer including the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the minimum established design limit.

5.5.18 Configuration Risk Management Program (CRMP)

[Not used

OR

This program provides controls for Completion Times. The program shall ensure that the assessment of configuration-specific risk to support the extension of Completion Times, and reassessment of configuration changes, and implementation of compensatory measures and actions at the appropriate risk thresholds are performed sufficient to assure the associated Limiting Conditions for Operation are met.

a. When entering into this specification, the following actions shall be taken in accordance with [NEI 06-09 (Revision y), “Risk-Managed Technical Specifications (RMTS) Guidelines” and supplemental documentation].”

   1. Within the completion time of the referencing specification determine that the plant configuration is acceptable beyond the completion time,

   AND

   2. Calculate the Risk-Informed Completion Time (RICT),

   AND

   3. Restore required subsystems or components to operable status within the RICT or 30 days, whichever is less.

   OR

   Take the ACTIONs required in the referencing specification for the required action and associated completion time not met.

b. The RICT shall be recalculated whenever plant configuration change occurs in accordance with NEI 06-09.

5.5 Programs and Manuals

5.5.18 Configuration Risk Management Program (CRMP) (continued)

c. This program shall satisfy all the requirements specified in NEI 06-09 including, but not limited to, the following:

1. Station procedure of the CRMP process with specifying the station functional organizations and personnel responsible for each action of CRMP implementation,

2. Training of responsible personnel,

3. PRA model to meet the technical adequacy requirements of NEI 06-09, [and supplementary documentation on PRA development].

4. Appropriate CRM tool.]

5.5.19 Surveillance Frequency Control Program

[Not used

OR

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with [NEI 04-10 (Revision z), “Risk-Informed Method for Control of Surveillance Frequencies,” and supplemental documentation].

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.]

5.5 Programs and Manuals

5.5.20 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Main Control Room Emergency Filtration System (MCREFS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

   [The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

   1. ; and]

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the MCREFS, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

5.5 Programs and Manuals

5.5.20 Control Room Envelope Habitability Program (continued)

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5.21 Setpoint Control Program (SCP)

a. The Setpoint Control Program (SCP) implements the regulatory requirement of 10 CFR 50.36 (c)(1)(ii) (A) that technical specifications will include items in the category of limiting safety system settings (LSSS), which are settings for automatic protective devices related to those variables having significant safety functions.

b. The Nominal Trip Setpoint (NTSP), Allowable Value (AV), Performance Test Acceptance Criteria (PTAC) and Calibration Tolerance (CT) for each Technical Specification required automatic protection instrumentation function (i.e., reactor trip, ESFAS actuation and permissive interlocks) shall be calculated in conformance with the instrumentation setpoint methodology previously reviewed and approved by the NRC in [Title, Revision No., dated Month dd, yyyy, (MLxxxxxxxxx)], and the conditions stated in the associated NRC safety evaluation, [Letter to MHI from NRC, Title, dated Month dd, yyyy, (MLxxxxxxxxx)].

c. For each Technical Specification required automatic protection instrumentation function implemented with a conventional analog bistable, performance of a COT surveillance shall include the following:

1. The as-found value of the instrument channel trip setting shall be compared with the previous as-left value or the specified NTSP.

i. If the as-found value of the instrument channel trip setting differs from the previous as-left value or the specified NTSP by more than the PTAC, but less than the specified AV, then the instrument channel shall be evaluated to verify that it is functioning in accordance with its design basis before declaring the surveillance requirement met and returning the instrument channel to service. This condition shall be dispositioned by the plant's corrective action program.

ii. If the as-found value of the instrument channel trip setting differs from the specified NTSP by more than the specified AV, then the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

2. The instrument channel trip setting shall be set or confirmed to be within the specified CT around the NTSP at the completion of each COT surveillance; otherwise, the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

d. For each Technical Specification required automatic protection instrumentation function implemented with a conventional analog bistable, the difference between the instrument channel trip setting as-found value and either the previous as-left value or the specified NTSP shall be trended and evaluated to verify that the instrument channel is functioning in accordance with its design basis.

e. For each Technical Specification required automatic protection instrumentation function implemented with a binary sensor (e.g., pressure switches, UV relays), performance of a CHANNEL CALIBRATION surveillance shall include the following:

1. The as-found value of the instrument channel state change shall be compared with the previous as-left value or the specified NTSP.

i. If the as-found value of the instrument channel state change differs from the previous as-left value or the specified NTSP by more than the PTAC, but less than the specified AV, then the instrument channel shall be evaluated to verify that it is functioning in accordance with its design basis before declaring the surveillance requirement met and returning the instrument channel to service. This condition shall be dispositioned by the plant's corrective action program.

ii. If the as-found value of the instrument channel state change differs from the specified NTSP by more than the specified AV, then the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

2. The instrument channel state change shall be set or confirmed to be within the specified CT around the NTSP at the completion of each CHANNEL CALIBRATION surveillance; otherwise, the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

f. For each Technical Specification required automatic protection instrumentation function implemented with a binary sensor, the difference between the instrument channel state change as-found value and either the previous as-left value or the specified NTSP shall be trended and evaluated to verify that the instrument channel is functioning in accordance with its design basis.

g. For each Technical Specification required automatic protection instrumentation function implemented with an analog sensor (e.g., pressure transmitter), performance of a CHANNEL CALIBRATION surveillance shall include the following:

1. The as-found value of the instrument channel calibration setting shall be compared with the previous as-left value or the specified calibration setting at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range.

i. If any as-found calibration setting value is outside the two-sided limits of “previous as-left value ± PTAC” or “calibration setting ± PTAC,” but inside the specified limits of ± AV, then the instrument channel shall be evaluated to verify that it is functioning in accordance with its design basis before declaring the surveillance requirement met and returning the instrument channel to service. This condition shall be dispositioned by the plant’s corrective action program.

ii. If any as-found calibration setting value is outside of the two-sided limits of ± AV, then the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

2. The instrument channel calibration settings shall be set or confirmed to be within the specified CT around the five calibration settings (0%, 25%, 50%, 75%, and 100%) at the completion of each CHANNEL CALIBRATION surveillance; otherwise, the surveillance requirement is not met and the instrument channel shall be immediately declared inoperable.

h. For each Technical Specification required automatic protection instrumentation function implemented with an analog sensor, the difference between the instrument channel calibration setting (0%, 25%, 50%, 75% and 100%) as-found value and either the previous as-left value or the specified calibration setting shall be trended and evaluated to verify that the instrument channel is functioning in accordance with its design basis.

i. The SCP shall establish a document containing the current values of the specified NTSP, AV, PTAC, and CT for each Technical Specification required automatic protection instrumentation function, and references to the calculation documentation. Changes to this document shall be governed by the regulatory requirements of 10 CFR 50.59. In addition, changes to the specified NTSP, AV, PTAC, and CT values shall be governed by the approved setpoint methodology. This document, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

j. For each Technical Specification required automatic protection instrumentation function implemented with a digital bistable, the Nominal Trip Setpoint value shall be confirmed during the software MEMORY INTEGRITY CHECK (MIC).

---------------------------------------REVIEWER'S NOTE---------------------------------------

The referenced NRC approved setpoint methodology shall meet the following guidance, and shall be applicable to Technical Specification required automatic protection instrumentation function surveillances that require verification that channel trip settings, state change values, and calibration settings are within the necessary range and accuracy (e.g., COT, CHANNEL CALIBRATIONS):

1. The methodology allows little variation in the values calculated by different analysts using identical input values (such as uncertainties and channel calibration drift).

2. The as-left value of the instrument channel (applicable to trip settings, state change values, and calibration settings) shall be the value at which the channel was set or left at the completion of the surveillance with no additional adjustment of the instrument channel.

3. The as-found value of the instrument channel (applicable to trip settings, state change values, and calibration settings) shall be the value measured during the subsequent performance of the surveillance before making any adjustment to the instrument channel that could change the value.

4. If the requirements of 5.5.21.c.1 or 5.5.21.e.1 are satisified by comparing the as-found value to the specified NTSP, then the following conditions shall be applied:

    a. The setting tolerance band (i.e., the specified CT) must be less than or equal to the square root of the sum of the squares of reference accuracy, measurement and test equipment errors, and readability uncertainties;

    b. The setting tolerance band (i.e., the specified CT) must be included in the total loop uncertainty; and

    c. The pre-defined test acceptance criteria band (i.e., the specified PTAC) for the as-found value must include either the setting tolerance band (the specified CT) or the uncertainties associated with the setting tolerance band (the specified CT), but not both of these.

5. If the requirements of 5.5.21.g.1 are satisfied by comparing the as-found value to the specified calibration setting, then the following conditions shall be applied:

    a. The setting tolerance band (i.e., the specified CT) must be less than or equal to the square root of the sum of the squares of reference accuracy, measurement and test equipment errors, and readability uncertainties;

b. The setting tolerance band (i.e., the specified CT) must be included in the total loop uncertainty; and

c. The pre-defined test acceptance criteria band (i.e., the specified PTAC) for the as-found value must include either the setting tolerance band (the specified CT) or the uncertainties associated with the setting tolerance band (the specified CT), but not both of these.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the tables and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements [in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979]. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.2 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the unit in the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6 Reporting Requirements

5.6.3 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each cycle, or prior to any remaining portion of a cycle, and shall be documented in the COLR for the following:

2.1.1, “Reactor Core SLs”
3.1.1, “SHUTDOWN MARGIN (SDM)”
3.1.3, “Moderator Temperature Coefficient (MTC)”
3.1.5, “Shutdown Bank Insertion Limits”
3.1.6, “Control Bank Insertion Limits”
3.2.1, “Heat Flux Hot Channel Factor ($F_Q(Z)$ (CAOC-W(Z) Methodology)”
3.2.2, “Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)”
3.2.3, “AXIAL FLUX DIFFERENCE (Constant Axial Offset Control (CAOC) Methodology)”
3.3.1, “Reactor Trip System (RTS) Instrumentation”
3.4.1, “RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits”
3.9.1, “Boron Concentration”

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. MUAP-07026-P, “Mitsubishi Reload Evaluation Methodology”, August, 2013.

   (Methodology for Specifications 2.1.1 - Reactor Core SLs, 3.1.1 - SHUTDOWN MARGIN, 3.1.3 - Moderator Temperature Coefficient, 3.1.5 - Shutdown Bank Insertion Limits, 3.1.6 - Control Bank Insertion Limits, 3.2.1 - Heat Flux Hot Channel Factor, 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor, 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control), 3.3.1 - Reactor Trip System (RTS) Instrumentation, and 3.9.1 - Boron Concentration.)

2. WCAP-8385, “Power Distribution Control and Load Following Procedures - Topical Report,” September 1974 (Westinghouse Proprietary) and WCAP-8403 (Non-Proprietary).

   (Methodology for Specification 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control).)

5.6 Reporting Requirements

5.6.3 CORE OPERATING LIMITS REPORT (COLR) (continued)

3. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, “Branch Technical Position 4-1, Westinghouse Constant Axial Offset Control (CAOC)”, Rev. 3, March 2007.

   (Methodology for Specification 3.2.3 - AXIAL FLUX DIFFERENCE (Constant Axial Offset Control).)

4. WCAP-10216-P-A, Rev.1A, “Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification,” February 1994 (Westinghouse Proprietary) and WCAP-10217-A, Rev. 1A (Non-Proprietary).

   (Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor (W(Z) surveillance requirements).)

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each cycle to the NRC.

5.6 Reporting Requirements

5.6.4 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing, LTOP arming, as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

3.4.3, “RCS Pressure and Temperature (P/T) Limits”
3.4.12, “Low Temperature Overpressure Protection System”

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

MUAP-09016, “Pressure and Temperature Limits Report.”

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.5 Post Accident Monitoring Report

When a report is required by Condition B of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.6 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Prestressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken.

5.6 Reporting Requirements

5.6.7 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing, and

h. The effective plugging percentage for all plugging in each SG

5.0 ADMINISTRATIVE CONTROLS

[5.7 High Radiation Area]

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 <u>High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation</u>

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of radiation work permit or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for a radiation work permit or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area, or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(a) Be under the surveillance, as specified in the radiation work permit or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

(b) Be under the surveillance as specified in the radiation work permit or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift supervisor, radiation protection manager, or his or her designees, and

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of a radiation work permit or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for a radiation work permit or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

5.7 High Radiation Area

5.7.2 <u>High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation</u> (continued)

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(a) Be under surveillance, as specified in the radiation work permit or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(b) Be under surveillance as specified in the radiation work permit or equivalent, while in the area, by means of closed circuit television, or personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

US-APWR
Technical Specifications

Bases

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The above criterion a. is represented by the limit DNBR values stated in SL 2.1.1.1, which are determined using WRB-2 DNB correlation with RTDP and include uncertainties of DNB correlation and key input parameters relevant to DNBR analysis as described in Reference 2. The Reactor Trip System setpoints (Ref. 3), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS Flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the RPS and the steam generator safety valves.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in Ref. 4) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure provided in the COLR shows the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNB correlation.

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

BASES

SAFETY LIMITS (continued)

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the reactor core SLs. If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.

2. Subsection 4.4.1.1.

3. Subsection 7.2.1.

4. Chapter 15.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2485 psig. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4).

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without

APPLICABLE SAFETY ANALYSES (continued)

a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressurizer pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressurizer pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of any of the following:

a. Main steam relief valve,

b. Turbine Bypass,

c. Rod Control System,

d. Pressurizer Water Level Control, or

e. Pressurizer spray valve.

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel, piping, valves, and fittings under the ASME Code, Section III, is 110% of design pressure. Therefore, the SL on maximum allowable RCS pressure is 2733.5 psig.

APPLICABILITY	SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.
SAFETY LIMIT VIOLATIONS	If the RCS pressure SL is violated when the reactor is in MODE 1or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour. Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress
REFERENCES	1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and GDC 28. 2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000. 3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWX-5000. 4. 10 CFR 100. 5. Chapter 7.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

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

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

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

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

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

LCO 3.0.2 (continued)

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

LCO 3.0.3 (continued)

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

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

a. The LCO is now met,

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

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

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the

LCO 3.0.3 (continued)

allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.12, "Spent Fuel pit Water Level." LCO 3.7.12 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel pit." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.12 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.12 of "Suspend movement of irradiated fuel assemblies in the spent fuel pit" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

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

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

BASES

LCO 3.0.4 (continued)

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

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

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

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

LCO 3.0.4 (continued)

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

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

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

LCO 3.0.4 (continued)

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

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

LCO 3.0.5

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

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

b. The OPERABILITY of other equipment.

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

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

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

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

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

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

Specification 5.5.15, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

LCO 3.0.6 (continued)

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. A loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

EXAMPLE B 3.0.6-1

If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in supported System 5.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11 which is in turn supported by System 5.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO 3.0.6 (continued)

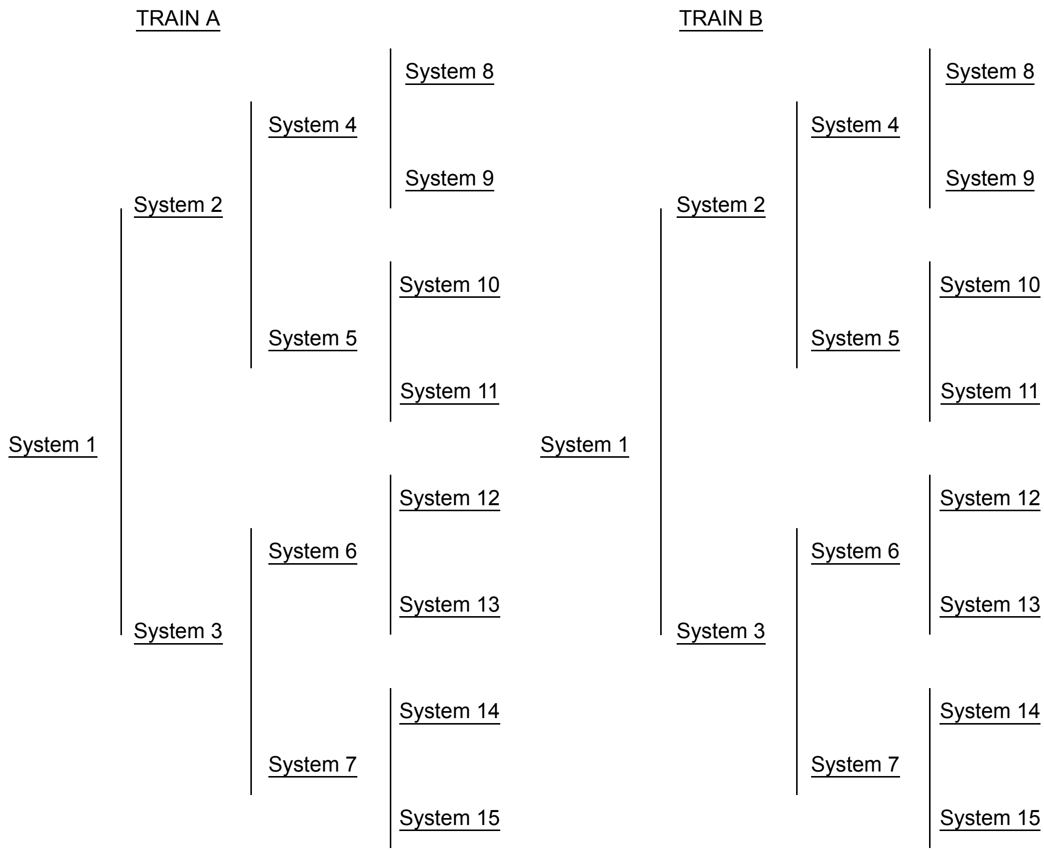

Figure B 3.0-1
Configuration of Trains and Systems

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low

BASES

LCO 3.0.6 (continued)

tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately address the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs 3.1.8 and 3.1.9 allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

BASES

LCO 3.0.8 (continued)

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.9

LCO 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

BASES

LCO 3.0.9 (continued)

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

------------------------------------- Reviewer's Note -----------------------------------
LCO 3.0.9 may be expanded to other initiating event categories provided plant-specific analysis demonstrates that the frequency of the additional initiating events is bounded by the generic analysis or if plant-specific approval is obtained from the NRC.

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado, hurricane or high wind.

BASES

LCO 3.0.9 (continued)

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles and hurricane missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

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

SR 3.0.1

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

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

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

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

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

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

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and

SR 3.0.1 (continued)

performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Emergency feedwater (EFW) pump turbine maintenance during refueling that requires testing at steam pressures > 800 psi. However, if other appropriate testing is satisfactorily completed, the EFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

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

SR 3.0.2

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

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

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance

SR 3.0.2 (continued)

being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations. As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

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

SR 3.0.3

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

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

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

SR 3.0.3 (continued)

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

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

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee’s Corrective Action Program.

SR 3.0.3 (continued)

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

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

SR 3.0.4

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

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to a Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance,

BASES

SR 3.0.4 (continued)

LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

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

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram. For MODE 3, 4, and 5, the primary safety analysis that relies on the SDM limits is the boron dilution analysis.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events,

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and below 230 cal/gm energy deposition for the rod ejection accident), and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution

b. An uncontrolled rod withdrawal from subcritical or low power condition, and

APPLICABLE SAFETY ANALYSES (continued)

c. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or a high pressurizer pressure trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB and the boron dilution accidents (Ref. 2) are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 3). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3, 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, “Control Bank Insertion Limits.”

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the borated water storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 110 gpm, it is possible to increase the boron concentration of the RCS by 142 ppm in approximately 32 minutes. If a boron worth of 7 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 110 gpm and 7 pcm/ppm represent typical values and are provided for the purpose of offering a specific example.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2 with $K_{eff} \geq 1.0$, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration,

b. Control bank position,

c. RCS average temperature,

d. Fuel burnup based on gross thermal energy generation,

e. Xenon concentration,

f. Samarium concentration, and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

[The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. Section 15.1 and 15.4.

3. 10 CFR 100.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is

BACKGROUND (continued)

critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured

APPLICABLE SAFETY ANALYSES (continued)

boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOC conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

BASES

APPLICABILITY (continued)

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

BASES

ACTIONS (continued)

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, 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. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. [The required subsequent Frequency of 31 EFPD, following the initial 60 EFPD after entering MODE 1, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.

2. Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the MTC is less than zero in MODE1 and MODE2 with $k_{eff} \geq 1.0$. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the lower limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in Chapter 15 (Ref. 2).

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2) and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

Chapter 15 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is maximum. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

APPLICABLE SAFETY ANALYSES (continued)

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOC or EOC. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOC and EOC. An EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is least negative near BOC; this upper bound must not be exceeded. This maximum upper limit occurs at BOC, all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

BASES

LCO (continued)

The upper and lower limits are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled control rod assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the upper MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

BASES

ACTIONS (continued)

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with k_{eff} < 1.0 to prevent operation with an MTC that is more positive than that assumed in safety analyses.

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

C.1

Exceeding the lower MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the lower MTC limit is exceeded at EOC, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time 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

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the least negative MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the upper MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the lower LCO limit. The 300 ppm SR value is sufficiently less negative than the lower LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

a. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the Lower limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the Lower limit.

c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the Lower limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.

2. Chapter 15.

3. MUAP-07026-P, “Mitsubishi Reload Evaluation Methodology”, August, 2013

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control or shutdown rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two or more groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two or more groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks.

BASES

BACKGROUND (continued)

BACKGROUND

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Rod Position Indication (RPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides a highly accurate indication of actual rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one data system fails, the RPI will go on half accuracy. The RPI System is capable of monitoring rod position within at least ± 12 steps with either full accuracy or half accuracy.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System (RCS) pressure boundary integrity and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 3). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 3).

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on control rod OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The control rod OPERABILITY requirements (i.e., trippability) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but that do not impact trippability, do not result in rod inoperability.

The requirement to maintain the rod alignment to within plus or minus 12 steps is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are bottomed and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction.

BASES

ACTIONS (continued)

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 3). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

BASES

ACTIONS (continued)

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F_{\Delta H}^N$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. The accident analyses presented in Chapter 15 (Ref. 3) that may be adversely affected will be evaluated to ensure that the analysis results remain valid for the duration of continued operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires

ACTIONS (continued)

increasing the RCS boron concentration to provide negative reactivity, as described in the Bases for LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. [The 12 hours Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2 with $K_{eff} \geq 1.0$, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. [The 92 day Frequency takes into consideration other information

BASES

SURVEILLANCE REQUIREMENTS (continued)

available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 500°F to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.

2. 10 CFR 50.46.

3. Subsection 15.0.2.5 and 15.4.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two or more groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two or more groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

BASES

BACKGROUND (continued)

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

    1. Specified acceptable fuel design limits or

    2. RCS pressure boundary integrity and

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. LCOs 3.1.5 and 3.1.6 ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2, and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

BASES

ACTIONS (continued)

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours 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

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

[Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28.

2. 10 CFR 50.46.

3. Section 15.1, 15.4 and Subsection 15.0.0.2.5.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two or more groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two or more groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits and overlap patterns are specified in the COLR. An example is provided for information only in Figure B 3.1.6-1. The control banks are required to be at or above the insertion limit lines.

Figure B 3.1.6-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The predetermined position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, will be at 135 steps for a fully withdrawn position of 265 steps. The fully withdrawn position is defined in the COLR.

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, “Rod Group Alignment Limits,” LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, “Control Bank Insertion Limits,” LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. Specified acceptable fuel design limits or

   2. Reactor Coolant System pressure boundary integrity and

b. The core remains subcritical after accident transients.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with k_{eff} < 1.0, where the LCO is not applicable. The allowed Completion Time of 6 hours 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

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

Verification of the control bank insertion limits are periodically performed to detect control banks that may be approaching the insertion limits. [A Frequency of 12 hours is sufficient since, normally, very little rod motion occurs in 12 hours. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. [A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, GDC 28.
2. 10 CFR 50.46.
3. Section 15.1, 15.4 and Subsection 15.0.0.2.

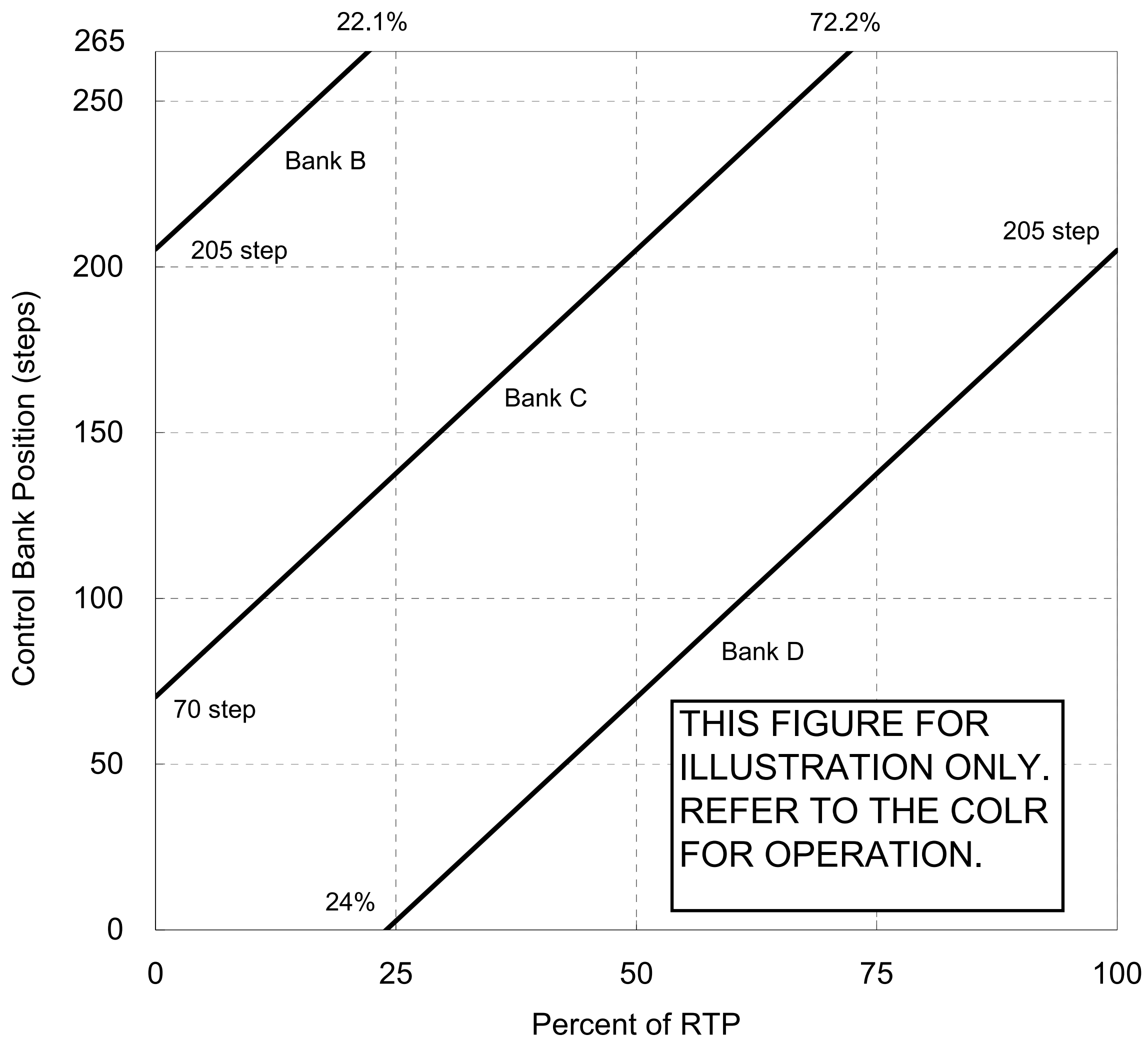

Figure B 3.1.6-1 (page 1 of 1)
Control Bank Insertion vs. Percent RTP

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indications to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms (CRDMs). The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two or more groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) which is included in the CRDM control system and the Rod Position Indication (RPI) System.

BASES

BACKGROUND (continued)

BACKGROUND

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is 6 steps. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the RPI will go on half accuracy with an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the normal indication accuracy of the RPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indication channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indications monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one RPI System and one Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indications to be OPERABLE requires meeting the SR of the LCO and the following:

a. The RPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits,"

b. For the RPI System there are no failed coils, and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the RPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the RPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indication channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the RPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indication and each demand position indication. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indication.

A.1

When one RPI channel per group fails, the position of the rod may still be determined indirectly by use of the movable Incore detectors. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1 or C.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 2).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1, B.2, B.3, and B.4

When more than one RPI per group fail, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur. Together with the indirect position determination available via

ACTIONS (continued)

ACTIONS

movable incore detectors will minimize the potential for rod misalignment. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition.

Monitoring and recording reactor coolant T_{avg} help assure that significant changes in power distribution and SDM are avoided. The once per hour Completion Time is acceptable because only minor fluctuations in RCS temperature are expected at steady state plant operating conditions.

The position of the rods may be determined indirectly by use of the movable incore detectors. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, $F^N_{\Delta H}$ satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the nonindicating rods have not been moved. Verification of control rod position once per 8 hours is adequate for allowing continued full power operation for a limited, 24 hour period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the RPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Action of C.1 or C.2 below is required.

C.1 and C.2

These Required Actions clarify that when one or more rods with inoperable position indications have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 and A.2, or B.1 are still appropriate but must be initiated promptly under Required Action C.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

BASES

ACTIONS (continued)

D.1.1 and D.1.2

With one demand position indication per bank inoperable, the rod positions can be determined by the RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indications are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits (Ref. 2). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

E.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time 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

SR 3.1.7.1

Verification that the RPI agrees with the demand position within 12 steps ensures that the RPI is operating correctly. Since the RPI does not display the actual shutdown rod positions at the beginning and end of travel, only points within the indicated ranges are required in comparison.

This Surveillance is performed prior to reactor criticality after each removal of the reactor head, as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES	1.	10 CFR 50, Appendix A, GDC 13.
	2.	Section 15.1, 15.4 and Subsection 15.0.0.2.3.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions - MODE 1

BASES

BACKGROUND

The primary purpose of the MODE 1 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow the performance of instrumentation calibration tests and special PHYSICS TESTS. The exceptions to LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” and LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR)” are most often appropriate for xenon stability tests. The exceptions to LCO 3.1.4, “Rod Group Alignment Limits”, LCO 3.1.5, “Shutdown Bank Insertion Limit”, and LCO 3.1.6, “Control Bank Insertion Limits,” may be required in the event that it is necessary or desirable to do special PHYSICS TESTS involving abnormal rod or bank configurations.

Section XI of 10 CFR 50, Appendix B (Ref. 1), 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 the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed,

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

c. Verify the assumptions used to predict unit response,

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

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, low power, power ascension, and at power

BASES

BACKGROUND (continued)

operation, and after each refueling. The PHYSICS TESTS requirements for reloaded 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 (Ref. 4).

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS required for reload fuel cycles (Ref. 4) in MODE 1 are listed below:

a. Power Distribution – Intermediate Power,

b. Power Distribution – Full Power, and

c. HZP to HFP reactivity difference.

These tests are performed in MODE 1. These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance. The last two tests are performed at ≥ 90% RTP.

a. The Power Distribution – Intermediate Power Test measures the power distribution of the reactor core at intermediate power levels at least one time by 30% RTP and between 40% and 80% RTP. This test uses the incore flux detectors to measure core power distribution. The requirements for the Flux Symmetry Test described in ANSI/ANS-19.6.1-2011 (Ref. 4) are satisfied by the Power Distribution Test.

BASES

BACKGROUND (continued)

b. The Power Distribution – Full Power Test measures the power distribution of the reactor core at ≥ 90% RTP using incore flux detectors.

c. The HZP to HFP reactivity difference simply measures the critical boron concentration at > 90% RTP, with all rods fully withdrawn, the lead control bank being at or near its fully withdrawn position, and with the core at equilibrium xenon conditions.

For initial startups, there are two currently required tests that violate the referenced LCO. The Axial Flux Difference Instrumentation Calibration Test and Axial Power Distribution Oscillation Test, performed at approximately 50% and 75% RTP, require large axial flux difference that exceed the limits specified in the relevant LCO. And the Rod Cluster Control Assembly Misalignment Measurement and Radial Power Distribution Oscillation Test, performed at approximately 50% RTP, require individual rod misalignments that exceed the limits specified in the relevant LCO.

APPLICABLE SAFETY ANALYSES

The fuel is protected by an LCO, which preserves the initial conditions of the core assumed during the safety analyses. The methods for development of the LCO, which are superseded by this LCO, are described in Ref. 5. The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating controls or process variables to deviate from their LCO limitations.

Section 14.2 (Ref. 6) defines requirements for initial testing of the facility, including PHYSICS TESTS. The zero, low power, and power tests are summarized in this section. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-2011 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for 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. When one or more of the requirements specified in LCO 3.1.4, “Rod Group Alignment Limits,” LCO 3.1.5, “Shutdown Bank Insertion Limits,” LCO 3.1.6, “Control Bank Insertion Limits,” LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” or LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR)” are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the requirements of LCO 3.2.1, “Heat Flux Hot Channel Factor ($F_Q(Z)$),” and LCO 3.2.2, “Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$),” are satisfied, power level is maintained ≤ 85% RTP, and SDM is within the limits specified in the COLR.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, LCO 3.1.8 requires surveillance of the hot channel factors and SDM to verify that their limits are not being exceeded.

PHYSICS TESTS include measurements of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down 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 Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. 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 allows selected control rods and shutdown rods to be positioned outside their specified alignment limits and insertion limits to conduct PHYSICS TESTS in MODE 1, to verify certain core physics parameters. The power level is limited to ≤ 85% RTP and the power range neutron flux trip setpoint is set at 10% RTP above the PHYSICS TESTS power level with a maximum setting of 90% RTP. Violation of LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, LCO 3.2.3, or LCO 3.2.4, during the performance of PHYSICS TESTS does not pose any threat to the integrity of the fuel as long as the requirements of LCO 3.2.1 and LCO 3.2.2 are satisfied and provided:

LCO (continued)

a. THERMAL POWER is maintained ≤ 85% RTP,

b. Power Range Neutron Flux – High trip setpoints are ≤ 10% RTP above the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP, and

c. SDM is within the limits specified in the COLR.

Operation with THERMAL POWER ≤ 85% RTP during PHYSICS TESTS provides an acceptable thermal margin when one or more of the applicable LCOs is out of specification. The Power Range Neutron Flux – High trip setpoint is reduced so that a similar margin exists between the steady state condition and the trip setpoint that exists during normal operation at RTP.

APPLICABILITY

This LCO is applicable in MODE 1 when performing PHYSICS TESTS. The applicable PHYSICS TESTS are performed at ≤ 85% RTP. Other PHYSICS TESTS are performed at full power but do not require violation of any existing LCO, and therefore do not require a PHYSICS TESTS exception. The PHYSICS TESTS performed in MODE 2 are covered by LCO 3.1.9, "PHYSICS TESTS Exception – MODE 2."

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

ACTIONS (continued)

B.1 and B.2

When THERMAL POWER is > 85% RTP, the only acceptable actions are to reduce the THERMAL POWER to ≤ 85% RTP or to suspend the PHYSICS TESTS exceptions. With the PHYSICS TESTS exceptions suspended, the PHYSICS TESTS may proceed if all other LCO requirements are met. Fuel integrity may be challenged with control rods or shutdown rods misaligned and THERMAL POWER > 85% RTP. The allowed Completion Time of 1 hour is reasonable, based on operating experience, for completing the Required Actions in an orderly manner and without challenging plant systems. This Completion Time is also consistent with the Required Actions of the LCOs that are suspended by the PHYSICS TESTS.

C.1 and C.2

When the Power Range Neutron Flux – High trip setpoints are > 10% RTP above the PHYSICS TESTS power level or > 90% RTP, the Reactor Trip System (RTS) may not provide the required degree of core protection if the trip setpoint is greater than the specified value.

The only acceptable actions are to restore the trip setpoint to the allowed value or to suspend the performance of the PHYSICS TESTS exceptions. The Completion Time of 1 hour is based on the practical amount of time it may take to restore the Neutron Flux – High trip setpoints to the correct value, consistent with operating plant safety. This Completion Time is consistent with the Required Actions of the LCOs that are suspended by the PHYSICS TESTS.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

Verification that the THERMAL POWER level is ≤ 85% RTP will ensure that the required core protection is provided during the performance of PHYSICS TESTS. Control of the reactor power level is a vital parameter and is closely monitored during the performance of PHYSICS TESTS. A Frequency of 1 hour is sufficient for ensuring that the power level does not exceed the limit.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.2

Verification of the Power Range Neutron Flux – High trip setpoints within 8 hours prior to initiation of the PHYSICS TESTS will ensure that the RTS is properly set to perform PHYSICS TESTS.

SR 3.1.8.3

The performance of SR 3.2.1.1 and SR 3.2.2.1 measures the core $F_Q(Z)$ and the $F^N_{\Delta H}$, respectively. If the requirements of these LCOs are met, the core has adequate protection from exceeding its design limits, while other LCO requirements are suspended. The Frequency of 12 hours is based on operating experience and the practical amount of time that it may take to run an incore flux map and calculate the hot channel factors.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. Reactor Coolant System (RCS) boron concentration,

b. Control bank position,

c. RCS average temperature,

d. Fuel burnup based on gross thermal energy generation,

e. Xenon concentration,

f. Samarium concentration,

g. Moderator defect, and

h. Doppler defect.

The frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident without the required SDM.

BASES

REFERENCES

1. 10 CFR 50, Appendix B, Section XI

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 3, March, 2007.

4. ANSI/ANS-19.6.1-2011, January 13, 2011

5. MUAP-07026-P, “Mitsubishi Reload Evaluation Methodology”, August, 2013

6. Section 14.2.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.9 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), 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 the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed,

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

c. Verify the assumptions used to predict unit response,

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

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, and after each refueling. 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 (Ref. 4).

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

BASES

BACKGROUND (continued)

The PHYSICS TESTS required for reload fuel cycles (Ref. 4) in MODE 2 are listed below:

a. Critical Boron Concentration - Control Rods Withdrawn,

b. Control Rod Worth, and

c. Isothermal Temperature Coefficient (ITC)

These tests are performed in MODE 2. These and other supplementary tests may be required to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration - Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, the lead control bank is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test should not violate any of the referenced LCOs.

BASES

BACKGROUND (continued)

b. The Control Rod Worth Test is used to measure the reactivity worth of selected control banks. This test is performed at HZP and has three alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining control banks. The second method, the Rod Swap Method, measures the worth of a predetermined reference bank using the Boron Exchange Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted into the core. The worth of the selected bank is inferred, based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining control banks. The third method, the Boron Endpoint Method, moves the selected control bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the selected control bank. This sequence is repeated for the remaining control banks. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

c. The ITC Test measures the ITC of the reactor. This test is performed at HZP and has two methods of performance. The first method, the Slope Method, varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The second method, the Endpoint Method, changes the RCS temperature and measures the reactivity at the beginning and end of the

BASES

BACKGROUND (continued)

temperature change. The ITC is the total reactivity change divided by the total temperature change. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in Ref. 5. The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

Section 14.2 (Ref.6) defines requirements for initial testing of the facility, including PHYSICS TESTS. The zero, low power, and power tests are summarized in this section. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-2011 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for 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. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)," LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP the reactor coolant temperature is kept ≥ 541°F, and SDM is within the limits provided in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. 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 allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. One power range neutron flux channel may be bypassed, reducing the number of required channels from 4 to 3. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3 and 15.c may be reduced to 3 required channels during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 541°F,

b. SDM is within the limits provided in the COLR, and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY

This LCO is applicable when performing low power PHYSICS TESTS. The Applicability is stated as "during PHYSICS TESTS initiated in MODE 2" to ensure that the 5% RTP maximum power level is not exceeded. Should the THERMAL POWER exceed 5% RTP, and consequently the unit enter MODE 1, this Applicability statement prevents exiting this Specification and its Required Actions.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < 541°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 541°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL CALIBRATION is performed on each power range and intermediate range channel per SR 3.3.1.9, consistent with Specification 5.5.21, Setpoint Control Program (SCP), prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.9.2

Verification that the RCS lowest loop T_{avg} is ≥ 541°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. [Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.1.9.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. [Verification of the THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.1.9.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration,

b. Control bank position,

c. RCS average temperature,

BASES

SURVEILLANCE REQUIREMENTS (continued)

d. Fuel burnup based on gross thermal energy generation,

e. Xenon concentration,

f. Samarium concentration,

g. Isothermal temperature coefficient (ITC), when below the zero power testing range,

h. Moderate defect, when above the zero power testing range, and

i. Doppler defect, when above the zero power testing range.

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical or critical but below the zero power testing range, and the fuel temperature will be changing at the same rate as the RCS.

[The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 3, March, 2007.

4. ANSI/ANS-19.6.1-2011, January 13, 2011.

5. MUAP-07026-P, “Mitsubishi Reload Evaluation Methodology”, August, 2013

6. Section 14.2.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (CAOC-W(Z) Methodology)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO(QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near equilibrium conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ which are present during non-equilibrium situations such as load following or power ascension.

To account for these possible variations, the equilibrium value of $F_Q(Z)$ is adjusted as $F_Q^W(Z)$ by an elevation dependent factor that accounts for the calculated worst case transient conditions.

Core monitoring and control under non-equilibrium conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

BASES

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, 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 departure from nucleate boiling (DNB) condition,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm (Ref. 2), 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 (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$F_Q(Z) \leq (CFQ / P)$ for $P > 0.5$

$F_Q(Z) \leq (CFQ / 0.5)$ for $P \leq 0.5$

where: CFQ is the $F_Q(Z)$ limit at RTP provided in the COLR, and

P = THERMAL POWER / RTP

LCO (continued)

For this facility, the actual values of CFQ is given in the COLR; however, CFQ is normally a number on the order of 2.6.

For Constant Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F_Q^C(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. Then,

$$F_Q^C(Z) = F_Q^M(Z) * F_Q^U$$

where F_Q^U is a factor specified in the COLR that accounts for fuel manufacturing tolerances and flux map measurement uncertainty.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z) * W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR. The $F_Q^C(Z)$ is calculated at equilibrium conditions.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q^C(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time. The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations $F_Q^C(Z)$ of and would require power reductions within 15 minutes of $F_Q^C(Z)$ the determination, if necessary to comply with the decreased maximum allowable power level. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

A reduction of the Power Range Neutron Flux - High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux - High trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Power Range Neutron Flux - High trip setpoints.

BASES

ACTIONS (continued)

A.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determination of $F_Q^C(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum allowable Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition A is modified by a Note that requires Required Action A.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action A.1, even when Condition A is exited prior to performing Required Action A.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational

ACTIONS (continued)

transient occurs. Reducing the THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, maintains an acceptable absolute power density such that even if a transient occurred, core peaking factors are not exceeded.

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action B.1.

B.3

Reduction in the Overpower ΔT trip setpoints value of K_4 by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action B.1.

B.4

Verification that $F_Q^W(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action B.1 ensures that core conditions during operation at higher power levels and future operation are consistent with safety analyses assumptions.

Condition B is modified by a Note that requires Required Action B.4 to be performed whenever the Condition is entered. This ensures that SR 3.2.1.1 and SR 3.2.1.2 will be performed prior to increasing THERMAL POWER above the limit of Required Action B.1, even when Condition A is exited prior to performing Required Action B.4. Performance of SR 3.2.1.1 and SR 3.2.1.2 are necessary to assure $F_Q(Z)$ is properly evaluated prior to increasing THERMAL POWER.

BASES

ACTIONS (continued)

C.1

If Required Actions A.1 through A.4 or B.1 through B.4 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z) * F_Q^U$, where F_Q^U is an measurement uncertainty factor specified in the COLR. $F_Q^C(Z)$ is then compared to its specified limits.

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

[The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The limit with which $F_Q^W(Z)$ is compared varies inversely with power above 50% RTP.

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. Typically, $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 15% inclusive and

b. Upper core region, from 85 to 100% inclusive.

The top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. If $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^M(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in $F_Q^C(Z)$,it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by a factor specified in the COLR (Ref. 5) or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

[The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50.46, 1974.
2. Subsection 15.0.0.1.2
3. 10 CFR 50, Appendix A, GDC 26.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
5. WCAP-10216-P-A, Rev. 1A, "Relaxation of Constant Axial Offset Control (and) F_Q Surveillance Technical Specification," February 1994.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

BASES

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition,

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm (Ref. 1), and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor $(F^N_{\Delta H})$," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of is $F^N_{\Delta H}$ allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being

APPLICABILITY (continued)

transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux - High trip setpoints to ≤ 55% RTP in accordance with

BASES

ACTIONS (continued)

Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

ACTIONS (continued)

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by a measurement uncertainty factor specified in the COLR, before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

[The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 15.0.0.1.2.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The operating scheme used to control the axial power distribution, CAOC, involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during unit maneuvers.

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the Fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The frequency of monitoring the AFD by the computer is once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to assess the status of the penalty deviation time. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFDs for two or more OPERABLE excore channels are outside the target band and the THERMAL POWER is > 90% RTP. During operation at THERMAL POWER levels < 90% RTP but > 15% RTP, the computer sends an alarm message when the cumulative penalty deviation time is > 1 hour in the previous 24 hours.

BASES

BACKGROUND (continued)

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) and QPTR LCOs limit the radial component of the peaking factors.

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The CAOC methodology (Refs. 1 and 2) entails:

a. Establishing an envelope of allowed power shapes and power densities,

b. Devising an operating strategy for the cycle that maximizes unit flexibility (maneuvering) and minimizes axial power shape changes,

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics, and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in the safety analyses. This ensures that fuel cladding integrity is maintained for the postulated accidents. AOOs, assumed to begin from within the AFD limits, are used to confirm the adequacy of Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 2). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup. With THERMAL POWER ≥ 90% RTP, the AFD must be kept within the target band. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

Figure B 3.2.3-1 shows a typical target band and typical AFD acceptable operation limits.

The LCO is modified by four Notes. Note 1 states the conditions necessary for declaring the AFD outside of the target band. Notes 2 and 3 describe how the cumulative penalty deviation time is calculated. It is intended that the unit is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part b of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours, is allowed during which the unit may be operated

LCO (continued)

outside of the target band but within the acceptable operation limits provided in the COLR (Note 2). This penalty time is accumulated at the rate of 1 minute for each 1 minute of operating time within the power range of Part b of this LCO (i.e., THERMAL POWER ≥ 50% RTP). The cumulative penalty time is the sum of penalty times from Parts b and c of this LCO.

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part c of this LCO), deviations of the AFD outside of the target band are less significant. Note 3 allows the accumulation of 1/2 minute penalty deviation time per 1 minute of actual time outside the target band and reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distribution is prevented by limiting the accumulated penalty deviation time.

For surveillance of the power range channels performed according to SR 3.3.1.6, Note 4 allows deviation outside the target band for 16 hours and no penalty deviation time accumulated. Some deviation in the AFD is required for doing the NIS calibration with the incore detector system. This calibration is performed every 92 days.

APPLICABILITY

AFD requirements are applicable in MODE 1 above 15% RTP. Above 50% RTP, the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1).

Between 15% RTP and 90% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. The value of the AFD in these conditions does not affect the consequences of the design basis events.

Low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

ACTIONS

A.1

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

B.1

If the AFD cannot be restored within the target band, then reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes provides an acceptable time to reduce power to < 90% RTP without allowing the plant to remain in an unanalyzed condition for an extended period of time.

C.1

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band is allowed for up to 1 hour if the AFD is within the acceptable operation limits provided in the COLR. With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. The reduction to a power level < 50% RTP puts the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. (Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits.) The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

Condition C is modified by a Note that requires that Required Actions C.1 and C.2 must be completed whenever this Condition is entered.

BASES

ACTIONS (continued)

D.1

If Required Action C.1 is not completed within its required Completion Time of 30 minutes, the axial xenon distribution starts to become significantly skewed with the THERMAL POWER ≥ 50% RTP. In this situation, the assumption that a cumulative penalty deviation time of 1 hour or less during the previous 24 hours while the AFD is outside its target band is acceptable at < 50% RTP, is no longer valid.

Reducing the power level to < 15% RTP within the Completion Time of 9 hours and complying with LCO penalty deviation time requirements for subsequent increases in THERMAL POWER ensure that acceptable xenon conditions are restored.

This Required Action must also be implemented either if the cumulative penalty deviation time is > 1 hour during the previous 24 hours, or the AFD is not within the target band and not within the acceptable operation limits.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band. [The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The AFD should be monitored and logged more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.2

This Surveillance requires that the target flux difference is updated. [A Frequency of 31 effective full power days (EFPD) accounts for small changes that may occur in the target flux differences in that period due to burnup by performing SR 3.2.3.3. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

Alternatively, linear interpolation between the most recent measurement of the target flux differences and a predicted end of cycle value provides a reasonable update because the AFD changes due to burnup tend toward 0% AFD. When the predicted end of cycle AFD from the cycle nuclear design is different from 0%, it may be a better value for the interpolation.

SR 3.2.3.3

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

[A Frequency of 31 EFPD after each refueling and 92 EFPD thereafter for remeasuring the target flux differences adjusts the target flux difference for each excore channel to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore excore calibrations that may have occurred in the interim. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

A Note modifies this SR to allow the predicted end of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

REFERENCES

1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

2. Subsection 15.0.0.2.3.

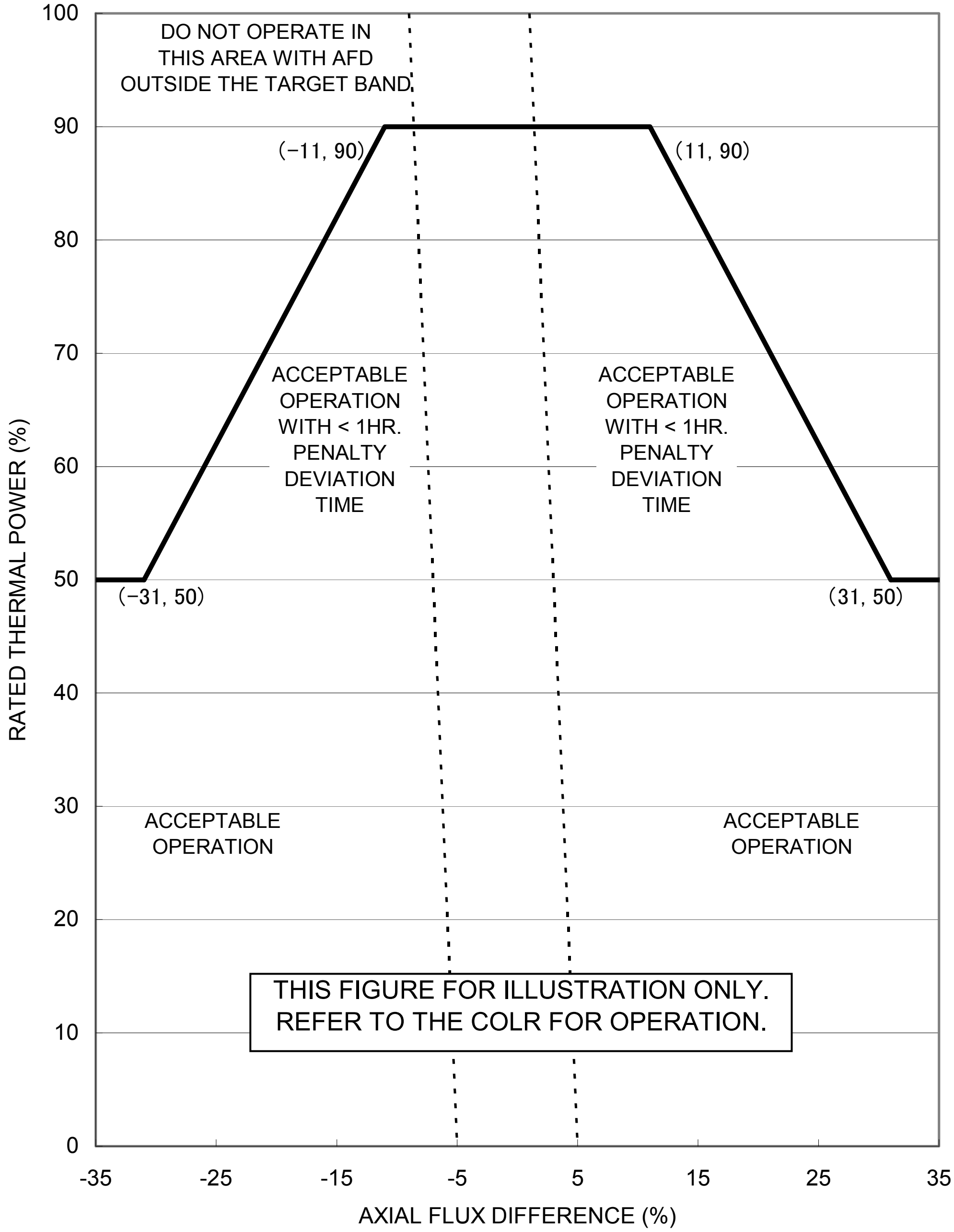

Figure B 3.2.3-1 (Page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
and Target Band Limits as a Function
of RATED THERMAL POWER

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1),

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition,

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm (Ref. 2), 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 (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and $(F^N_{\Delta H})$ is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require power reduction within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable power level. Decreases in QPTR would allow increasing the maximum allowable power level and increasing power up to this revised limit.

ACTIONS (continued)

A.2

After completion of Required Action A.1, the QPTR alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}^N$ and $F_Q(Z)$ within the Completion Time of 24 hours after achieving equilibrium conditions from a Thermal Power reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to support flux mapping. A Completion Time of 24 hours after achieving equilibrium conditions from Thermal Power reduction per Required Action A.1 takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}^N$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}^N$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction

ACTIONS (continued)

accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

<u>A.5</u>

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limits prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the QPTR is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

<u>A.6</u>

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification

ACTIONS (continued)

that $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, and $F_{\Delta H}^N$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. [The Frequency of 7 days takes into account other information and alarms available to the operator in the control room. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. [Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for ensuring that any tilt remains within its limits. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt.

The symmetric thimble flux map can be used to generate symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore monitoring of QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

BASES

REFERENCES	1.	10 CFR 50.46.
	2.	Subsection 15.0.0.1.2.
	3.	10 CFR 50, Appendix A, GDC 26.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices...so chosen that automatic protective action will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The Nominal Trip Setpoint, recorded and maintained in a document established by the Setpoint Control Program (SCP), is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the Nominal Trip Setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the Nominal Trip Setpoint plays an important role in ensuring that SLs are not exceeded. As such, the Nominal Trip Setpoint meets the definition of an LSSS (Ref. 1) and is used to meet the requirement that they be contained in the Technical Specifications. This is an acceptable approach for digital systems because the digital setpoints do not drift as in analog systems. The Nominal Trip Setpoint is applicable to automatic protection instrumentation functions for Reactor Trip, ESF Actuation Systems (ESFAS) actuation and permissive interlocks.

BACKGROUND (continued)

Technical Specifications contain Allowable Values related to the OPERABILITY of equipment required for safe operation of the facility. The Allowable Value accommodates expected drift in the analog components of the channel that would have been specifically accounted for in the setpoint methodology for calculating the Nominal Trip Setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as-found" settings of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to recalibrate the device to account for further drift during the next surveillance interval.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value.

The Allowable Value, recorded and maintained in a document established by the Setpoint Control Program (SCP), is considered a limiting value such that a channel is OPERABLE if the as-found value does not exceed the Allowable Value during CHANNEL CALIBRATION. The Allowable Value is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

For analog measurements, the CHANNEL CALIBRATION verifies the channel accuracy at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range. For binary measurements, the CHANNEL CALIBRATION verifies the accuracy of the channel's state change at the required setpoint. As such, the Allowable Value accounts for the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a SL is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval.

Note that, although the channel is "OPERABLE" under these circumstances, the channel shall be left adjusted to a value within the established channel Calibration Tolerance (CT) band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. The Calibration Tolerance, recorded and maintained in a document established by the SCP, is applicable to automatic

BACKGROUND (continued)

protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

If the as-found value of the device is found to have exceeded the Allowable Value, or the as-left value of the device cannot be adjusted to a value within the Calibration Tolerance, the device would be considered inoperable from a technical specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

In the Protection and Safety Monitoring System (PSMS), setpoints associated with analog measurements are stored as digital values that have no potential for variation due to time, environmental drift or component aging. For analog measurements, the only factors that can result in variation in the trip Functions reside in the uncertainties that are pertinent to the analog portion of the system. Therefore, for analog measurements in the PSMS, it is appropriate for the Allowable Value to be expressed in terms of values that are measured during periodic testing of the analog portion of the system (i.e., CHANNEL CALIBRATION).

For PSMS analog measurements, the as-found and as-left values are measured from sensor to digital Visual Display Unit (VDU) readout during CHANNEL CALIBRATION. The US-APWR enhances human performance by establishing a standard CHANNEL CALIBRATION method for all analog measurements, whereby the as-found and as-left values read at the VDU are measured at the same five calibration settings, regardless of the PSMS trip setpoint(s).

Since the PSMS trip logic and setpoints for analog measurements are stored as digital values with no drift potential, and those digital values are confirmed through the MEMORY INTEGRITY CHECK (MIC), the only untested area required to confirm channel operability pertains to the accuracy of the analog input signal. When the analog input accuracy is confirmed, by reading the digital values of the five point CHANNEL CALIBRATION settings on any VDU driven by the same digital value used in the controller that executes the trip Functions, the operability of the complete channel is confirmed, including the accuracy of all trip setpoints associated with that channel.

BASES

BACKGROUND (continued)

In the PSMS, setpoints associated with binary measurements are stored within the binary device itself. These setpoints have potential for variation due to time, environmental drift or component aging. However, these sensors are interfaced to the digital portion of the PSMS, which has no potential for variation due to time, environmental drift or component aging. For binary measurements, the only factors that can result in variation in the trip Functions reside in the uncertainties that are pertinent to the binary sensor itself. Therefore, for binary measurements in the PSMS, it is appropriate for the Allowable Value to be expressed in terms of values that are measured during periodic testing of the binary device (i.e., CHANNEL CALIBRATION).

For PSMS binary measurements, the as-found and as-left state change values are measured from sensor to VDU readout during CHANNEL CALIBRATION. The US-APWR enhances human performance by establishing a standard CHANNEL CALIBRATION method for all binary measurements, whereby the as-found and as-left values read at the VDU are measured at the channel's required state change.

Since the PSMS trip logic for binary sensors is stored as digital values with no drift potential, and those digital values are confirmed through the MIC, the only untested area required to confirm channel operability pertains to the accuracy of the binary input signal. When the binary input accuracy is confirmed, by reading the channel's state change on any VDU driven by the same digital value used in the controller that executes the trip Functions, the operability of the complete channel is confirmed, including the accuracy of the trip setpoint associated with that channel.

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

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB),

2. Fuel centerline melt shall not occur, and

3. The RCS pressure SL of 2733.5 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs.

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is segmented into four distinct but interconnected modules as illustrated in Chapter 7 (Ref. 2), and as identified below:

1. Field transmitters, process sensors or field contacts: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured,

2. The RPS, including Nuclear Instrumentation System (NIS): provides signal conditioning, analog to digital conversion, digital bistables for setpoint comparison, process algorithm actuation, compatible electrical signal output to the Reactor Trip Breakers (RTBs), and digital output to control board/control room/miscellaneous VDUs, and

3. Reactor trip breakers (RTBs): provide the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor.

4. Manual Reactor Trip switches: provide the Manual Reactor Trip Initiation in the control room.

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by "as-found" calibration data evaluated during the CHANNEL CALIBRATION and by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

Protection and Safety Monitoring System

Generally, four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. Four channels provides the capability for unlimited bypass of one channel while maintaining single failure criteria, therefore generally allowing a requirement for only three channels to be OPERABLE. The process control equipment provides signal conditioning, analog to digital conversion, comparable digital output signals for VDUs located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, a digital output from a digital bistable is processed for decision evaluation. Channel separation is maintained throughout the PSMS. Some unit parameters provide input only to the PSMS, while others are used by the PSMS and are retransmitted to the Plant Control and Monitoring System (PCMS) for use in one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

BACKGROUND (continued)

Generally, if a parameter is used for input to the protection circuits and a control function, three channels with a two-out-of-three logic are also sufficient to provide the required reliability and redundancy. When three or more channels are OPERABLE, the Signal Selection Algorithm (SSA) within the PCMS ensures the control systems can withstand an input failure to the control system without causing erroneous control system operation, which would otherwise require the protection function actuation. Since the input failure does not cause an erroneous control system action that challenges the protection function, the input failure is considered a single failure in the RTS and the RTS remains capable of providing its protective function with the remaining two OPERABLE channels. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-603-1991 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2. When there are less than three OPERABLE channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared channels, when there are only three required channels.

The RTB trains are arranged in a two-out-of-four configuration. Therefore, three logic trains are required to ensure no single random failure of a logic train will disable the RTS. The logic trains are designed such that testing required while the reactor is at power may be accomplished without causing trip. Provisions allow removing logic trains from service during maintenance.

<u>Allowable Values and RTS Setpoints</u>

The Nominal Trip Setpoints used in the digital bistables or binary sensors are based on the Analytical Limits defined in the accident analysis and the channel uncertainty. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing Time Delays are taken into account.

To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Nominal Trip Setpoints and Allowable Values are conservative to protect the Analytical Limits. The methodology identified in the SCP, used to calculate the Allowable Values and Nominal Trip Setpoints, incorporates all of the known uncertainties applicable to each channel (Ref. 12). The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint and Allowable Value.

BACKGROUND (continued)

The Nominal Trip Setpoint entered into the digital bistable or binary sensor is more conservative than that specified by the Analytical Limit. The Nominal Trip Setpoint accounts for measurement errors detectable by the CHANNEL CALIBRATION and other unmeasurable errors (such as the effects of anticipated environmental conditions), which are both considered in the Allowable Value for CHANNEL CALIBRATION. The Allowable Value serves as the Technical Specification OPERABILITY limit for the purpose of the CHANNEL CALIBRATION. One example of such a change in measurement error is drift during the surveillance interval. If the as-found value does not exceed the Allowable Value, the channel is considered OPERABLE.

The Nominal Trip Setpoint (i.e., LSSS) is the value at which the digital bistable or binary sensor is set. The Nominal Trip Setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on the stated channel uncertainties. Any channel is considered to be properly adjusted when the "as-left" value is within the established Calibration Tolerance (CT) band, in accordance with the methods and assumptions of the SCP. The Nominal Trip Setpoint value (i.e., expressed as a value without inequalities) for digital bistables, is confirmed during the MIC. The Nominal Trip Setpoint value (i.e., expressed as a value with inequalities) for binary sensors is confirmed during the CHANNEL CALIBRATION.

Nominal Trip Setpoints and Allowable Values, consistent with the requirements of the SCP, ensure that SLs are not violated during AOOs and that the consequences of Postulated Accidents (PAs) will be acceptable, provided the unit is operated from within the LCOs at the onset of the AOO or PA and the equipment functions as designed.

Within the PSMS controllers, Nominal Trip Setpoints and Time Constants are digital settings maintained in non-volatile software memory within each Reactor Protection System(RPS) train. Digital settings have no potential for variation due to time, environmental drift or component aging; therefore, these digital settings have no surveillance tolerance. Each PSMS controller has continuous automatic self-testing, which verifies that the digital Nominal Trip Setpoint and Time Constant settings are correct. Nominal Trip Setpoints and Time Constants are also verified periodically through the MIC which must be conducted with the affected PSMS controller out of service. A designated instrument channel is taken out of service for periodic CHANNEL CALIBRATION. SRs for the channels and trains are specified in the SRs section.

BACKGROUND (continued)

The Allowable Value is the maximum deviation that can be measured during CHANNEL CALIBRATION, whereby the channel is considered OPERABLE. This value includes the deviations that are included in the calculations that determined the Nominal Trip Setpoint. The “expected as-found value” shall be as specified in the plant-specific setpoint analysis. The expected as-found value reflects the expected normal drift of actual plant equipment, so that a degraded device can be identified before the Allowable Value limit is reached. The expected as-found value is also referred to as the Performance Test Acceptance Criteria (PTAC). The PTAC, recorded and maintained in a document established by the SCP, is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

Reactor Trip Breakers

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. There are eight RTBs, two from each of four RTB trains, arranged in a two-out-of-four configuration.

During normal operation the output from the RPS is a voltage signal that energizes the undervoltage coils in the RTBs. When protective action is required, the RPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a Reactor Trip signal from the RPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

The decision logic matrix Functions are described in the functional diagrams included in Reference 2. In addition to the Reactor Trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has built in continuous automatic self-testing that automatically tests the decision logic Functions while the unit is at power. When any one or two trains are taken out of service for testing, the other two trains are capable of providing unit monitoring and protection until the testing has been completed.

BACKGROUND (continued)

The Class 1E Electrical Room HVAC System is a support system and provides temperature control for the Reactor Trip Breaker Rooms where the RTBs are located. The system includes electric heating coils, chilled water cooling coils, fans, filters, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller.

The Class 1E Electrical Room HVAC System trains are each sized to satisfy 100% of the cooling and heating demand of two Reactor Trip Breaker Rooms. For RTBs to be OPERABLE, one of the associated Class 1E Electrical Room HVAC System trains, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, and capable of performing its support function.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS Functions to maintain the SLs during all AOOs and mitigates the consequences of PAs in all MODES in which the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 and 9 takes credit for most RTS Functions. RTS Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RTS Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. A channel is OPERABLE provided the "as-found" value, measured during surveillance testing, does not exceed its associated Allowable Value and provided the “as-left” value is within the specified calibration tolerance at the completion of each CHANNEL CALIBRATION. For analog measurements, Allowable Values are defined in terms pertinent to the five channel calibration settings 0%, 25%, 50%, 75% and 100%. For binary measurements there is one Allowable Value defined in terms pertinent to the state change at the Nominal Trip Setpoint. A Nominal Trip Setpoint is set more conservative than the Allowable Value to account for channel uncertainties. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of three or two channels in each instrumentation Function, three trains of Manual Reactor Trip Initiation, and three trains in each Automatic Trip Logic Function. Three OPERABLE instrumentation channels in a two-out-of-three configuration are required when one RTS channel is also used as a control system input. When there are three or more OPERABLE channels, the SSA within the control system prevents the possibility of a shared channel failing in such a manner that it creates a transient that requires RTS action. The input failure is considered a single failure in the RTS and RTS remains capable of providing its protective function with the remaining two OPERABLE channels. The SSA ensures there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. When there are less than three OPERABLE channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared channels, when there are only three required channels.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The two-out-of-three configuration allows one channel to be tripped during maintenance or testing without causing a Reactor Trip. Specific exceptions to the above general philosophy exist and are discussed below.

Due to redundant components within the PSMS, such as controllers, communication links and power supplies, an inoperable component may or may not result in an inoperable channel/train. Where an inoperable component results in an inoperable required channel/train, LCOs are entered. For inoperable components that do not result in inoperable channels/trains, LCOs are not entered.

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip Initiation

   The Manual Reactor Trip Initiation ensures that the control room operator can initiate a Reactor Trip at any time by using any two-out-of-four hardwired reactor trip switches in the control room. A Manual Reactor Trip Initiation accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Nominal Trip Setpoint.

   The LCO requires three Manual Reactor Trip Functions to be OPERABLE. Each train is controlled by a manual reactor trip switch. Each train activates two Reactor Trip Breakers in its respective train. Three independent trains are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Initiation Function.

   In MODE 1 or 2, Manual Initiation of a Reactor Trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the Manual Initiation Function must also be OPERABLE if one or more shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, Manual

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Initiation of a Reactor Trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted, there is no need to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the Manual Initiation Function is not required.

2. <u>High Power Range Neutron Flux</u>

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. Four channels are required because each channel measures neutron flux in one quadrant of the core. Anomalies occurring in one core quadrant can be seen by the neutron flux detector in that quadrant and by the neutron detectors in the two adjacent quadrants, but may not be detected by the detector in the opposite quadrant. Therefore, to ensure event detection and accommodate a single failure, neutron flux detectors must be OPERABLE in all four quadrants.

The NIS power range detectors also provide control inputs to the Rod Control System and the Steam Generator (SG) Water Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When there are three or more OPERABLE NIS power range channels, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. When there are less than three OPERABLE NIS power range channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared NIS power range channels.

Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a Reactor Trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. <u>High Setpoint</u>

The High Power Range Neutron Flux (High Setpoint) trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the High Power Range Neutron Flux (High Setpoint) channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the High Power Range Neutron Flux (High Setpoint) trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the High Power Range Neutron Flux (High Setpoint) does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. <u>Low Setpoint</u>

The LCO requirement for the High Power Range Neutron Flux (Low Setpoint) trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the High Power Range Neutron Flux (Low Setpoint) channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the High Power Range Neutron Flux (Low Setpoint) trip must be OPERABLE. This Function may be manually blocked by the operator when two-out-of-four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the High Power Range Neutron Flux (High Setpoint) trip Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 3, 4, 5, or 6, the High Power Range Neutron Flux (Low Setpoint) trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. High Power Range Neutron Flux Rate

The High Power Range Neutron Flux Rate trips use the same channels as discussed for Function 2 above. Four channels are required because each channel measures neutron flux in one quadrant of the core. Anomalies occurring in one core quadrant can be seen by the neutron flux detector in that quadrant and by the neutron detectors in the two adjacent quadrants, but not by the detector in the opposite quadrant. Therefore, to ensure event detection and accommodate a single failure, neutron flux detectors must be OPERABLE in all four quadrants.

a. Positive Rate

The High Power Range Neutron Flux Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and the accompanying ejection of the RCCA. This Function compliments the High Power Range Neutron Flux (High and Low Setpoint) trip Functions to ensure that the criteria are met for a rod ejection from the power range.

The LCO requires all four of the High Power Range Neutron Flux Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the High Power Range Neutron Flux Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the High Power Range Neutron Flux Positive Rate trip Function does not have to be OPERABLE because other RTS Functions and administrative controls will provide protection against positive reactivity additions. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this MODE.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

b. Negative Rate

The High Power Range Neutron Flux Negative Rate trip Function ensures that protection is provided for multiple rod drop accidents. At high power levels, a multiple rod drop accident could cause local flux peaking that would result in an unconservative local DNBR. DNBR is defined as the ratio of the heat flux required to cause a DNB at a particular location in the core to the local heat flux. The DNBR is indicative of the margin to DNB. No credit is taken for the operation of this Function for those rod drop accidents in which the local DNBRs will be greater than the limit.

The LCO requires all four High Power Range Neutron Flux Negative Rate channels to be OPERABLE.

In MODE 1 or 2, when there is potential for a multiple rod drop accident to occur, the High Power Range Neutron Flux Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the High Power Range Neutron Flux Negative Rate trip Function does not have to be OPERABLE because the core is not critical and DNB is not a concern. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the required SDM is increased during refueling operations. In addition, the NIS power range detectors cannot detect neutron levels present in this MODE.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. High Intermediate Range Neutron Flux

The High Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the High Power Range Neutron Flux (Low Setpoint) trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a Reactor Trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of High Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the High Power Range Neutron Flux (High Setpoint) trip and the High Power Range Neutron Flux Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 2 below the P-6 setpoint, the High Source Range Neutron Flux trip provides the core protection for reactivity accidents. In MODE 3, 4, or 5, the High Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. <u>High Source Range Neutron Flux</u>

The LCO requirement for the High Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the High Power Range Neutron Flux (Low Setpoint) trip Function. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted. Therefore, the functional capability at the specified Nominal Trip Setpoint is assumed to be available.

The High Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events.

In MODE 2 when below the P-6 setpoint and in MODES 3, 4, and 5 when there is a potential for an uncontrolled RCCA bank rod withdrawal accident, the High Source Range Neutron Flux trip must be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. Above the P-6 setpoint, the High Intermediate Range Neutron Flux trip and the High Power Range Neutron Flux (Low Setpoint) trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the High Source Range Neutron Flux trip may be manually bypassed which will also de-energize the NIS source range detectors. Above the P-10 setpoint, the High Source Range Neutron Flux trip is automatically bypassed and the NIS source range detectors are automatically de-energized.

In MODES 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of the Function to RTS logic are not required OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is initiated based on setpoints derived for DNB protection or core exit conditions. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include all pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit or core exit boiling is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Reactor Trip occurs if measured loop ΔT exceeds the lower setpoint of the DNB protection limit setpoint and the core exit boiling limit setpoint. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Nominal Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature,
- Pressurizer Pressure - the Nominal Trip Setpoint is varied to correct for changes in system pressure, and
- axial power distribution - $f(\Delta I)$, the Nominal Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Nominal Trip Setpoint is reduced in accordance with FSAR Section 7.2.1.4.3.1 (Ref. 2).

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Overtemperature ΔT trip Function is calculated for each loop as described in FSAR Section 7.2.1.4.3.1 (Ref. 2). Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control functions. The interface from the safety channels in the PSMS to the PCMS is through the SSA. When three or more temperature and pressure channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). When there are less than three OPERABLE temperature and pressure channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for temperature and pressure channels, since there are only three required channels.

Note that this Function also provides a signal to generate a turbine runback prior to reaching the Nominal Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a Reactor Trip.

The LCO requires three channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

The cycle dependent variables for this Function are specified in the COLR.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the High Power Range Neutron Flux (High Setpoint) trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Nominal Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature, and
- rate of change of reactor coolant average temperature - including dynamic compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per FSAR Section 7.2.1.4.3.2 (Ref. 2). Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are also used for other control functions. The interface from the safety channels in the PSMS to the PCMS is through the SSA. When three or more temperature channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). When there are less than three OPERABLE temperature channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for temperature channels, since there are only three required channels.

Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a Reactor Trip.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires three channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

The cycle dependent variables for this Function are specified in the COLR.

8. Pressurizer Pressure

The same sensors provide inputs to the High and Low Pressurizer Pressure trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide control inputs to the Pressurizer Pressure Control System. The interface from the safety channels in the PSMS to the PCMS is through the SSA. When three or more Pressurizer Pressure channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). When there are less than three OPERABLE pressure channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for Pressurizer Pressure channels, since there are only three required channels.

a. Low Pressurizer Pressure

The Low Pressurizer Pressure trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires three channels of Low Pressurizer Pressure to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, when DNB is a major concern, the Low Pressurizer Pressure trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or Turbine Inlet Pressure greater than approximately 10% of full power equivalent (P-13)). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

b. <u>High Pressurizer Pressure</u>

The High Pressurizer Pressure trip Function ensures that protection is provided against over pressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the High Pressurizer Pressure to be OPERABLE.

The High Pressurizer Pressure LSSS is selected to be below the pressurizer safety valve actuation pressure setting. This setting minimizes challenges to safety valves.

In MODE 1 or 2, the High Pressurizer Pressure trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the safety valves. In MODE 3, 4, 5, or 6, the High Pressurizer Pressure trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. High Pressurizer Water Level

The High Pressurizer Water Level trip Function provides a backup signal for the High Pressurizer Pressure trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A Reactor Trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of High Pressurizer Water Level to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the SSA. When three or more High Pressurizer Water Level channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). When there are less than three OPERABLE High Pressurizer Water Level channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for High Pressurizer Water Level channels, since there are only three required channels.

In MODE 1, when there is a potential for overfilling the pressurizer, the High Pressurizer Water Level trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the Pressurizer Water Level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Low Reactor Coolant Flow

The Low Reactor Coolant Flow trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding Reactor Trips due to normal variations in loop flow. Above the P-7 setpoint, the Reactor Trip on low flow in any one RCS loop is automatically enabled. Each RCS loop has four flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Low Reactor Coolant Flow channels per loop to be OPERABLE in MODE 1 above P-7.

In MODE 1 above the P-7 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. Below the P-7 setpoint, all Reactor Trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

11. Low Reactor Coolant Pump (RCP) Speed

The Low RCP Speed trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The speed of each RCP is monitored. Above the P-7 setpoint a low speed detected on two or more RCPs will initiate a Reactor Trip. The Nominal Trip Setpoint reflects only steady state instrument uncertainties as the detectors do not provide primary protection for any event that results in a harsh environment.

The LCO requires three Low RCP Speed channels (one channel per loop) to be OPERABLE in MODE 1 above P-7. One channel per loop is sufficient for this trip Function because the Low RCS Flow trip alone provides sufficient protection of unit SLs for loss of flow events. The Low RCP Speed trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump. Below the P-7 setpoint, all Reactor Trips on loss of flow are automatically blocked since no power distributions are expected to occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the Reactor Trip on loss of flow in two or more loops is automatically enabled.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

12. Steam Generator Water Level

The same sensors provide inputs to the Low SG Water Level trip and the High-High SG Water Level trip. Additionally, the level transmitters provide control inputs to the SG Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the SSA. When three or more High-High SG Water Level channels are OPERABLE for each Steam Generator, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). When there are less than three OPERABLE High-High SG Water Level channels for each Steam Generator, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for High-High SG Water LEvel channels, since there are only three required channels for each Steam Generator.

a. Low SG Water Level

The Low SG Water Level trip Function ensures that protection is provided against a loss of heat sink and actuates the Emergency Feedwater (EFW) System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low level in any SG is indicative of a loss of heat sink for the reactor. This Function also performs the ESFAS function of starting the EFW pumps on low SG level.

The LCO requires three channels of Low SG Water Level per SG to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, when the reactor requires a heat sink, the Low SG Water Level trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The EFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the EFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the Low SG Water Level Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the EFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

b. High-High SG Water Level

The High-High SG Water Level trip Function ensures that protection is provided against an excessive cooldown due to increase in feedwater flow. An increase in the feedwater flow rate will cause an increase in SG Water Level and reduction in the reactor coolant temperature. Reduction in the coolant temperature adds reactivity as a result of the positive moderator density coefficient, thereby increasing the reactor power.

This Function also performs the ESFAS functions of generating a Turbine Trip and initiating Main Feedwater Isolation.

The LCO requires three channels of the High-High SG Water Level trip Function to be OPERABLE in MODE 1 above P-7. The trip Function is automatically enabled on increasing power by the P-7 interlock and automatically blocked on decreasing power once the P-7 interlock is cleared. Although the High-High SG Water Level trip is blocked below the P-7 setpoint, the ESFAS functions to trip the turbine and isolate Main Feedwater are OPERABLE above and below the P-7 setpoint. These ESFAS functions allow the operator sufficient time to evaluate plant conditions and take corrective actions.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Turbine Trip

a. Turbine Emergency Trip Oil Pressure

The Turbine Emergency Trip Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a Turbine Trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any Turbine Trip from a power level below the P-7 setpoint, approximately 10% power, will not actuate a Reactor Trip. Four pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-four pressure switches will actuate a Reactor Trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the High Pressurizer Pressure trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Emergency Trip Oil Pressure to be OPERABLE in MODE 1 above P-7.

Below the P-7 setpoint, a Turbine Trip does not actuate a Reactor Trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a Turbine Trip, and the Turbine Emergency Trip Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip - Main Turbine Stop Valve Position

The Main Turbine Stop Valve Position trip Function anticipates the loss of heat removal capabilities of the secondary system following a Turbine Trip from a power level Above the P-7 setpoint. This action will actuate a Reactor Trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will normally operate in the presence of a single failure due to redundant limit switches on

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

each valve. However this trip Function is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the High Pressurizer Pressure trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Emergency Trip Oil Pressure Turbine Trip Function. Each main turbine stop valve is equipped with two limit switches that input to the RTS. If the limit switches indicate that all four stop valves are closed, a Reactor Trip is initiated.

The LSSS for this Function is set to assure channel trip occurs when the associated stop valve is completely closed.

The LCO requires four Main Turbine Stop Valve Position channels, one per valve, to be OPERABLE in MODE 1 above P-7. One channel on each valve must trip to cause Reactor Trip.

Below the P-7 setpoint, a load rejection can be accommodated by the Turbine Bypass System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip - Main Turbine Stop Valve Position trip Function does not need to be OPERABLE.

14. <u>ECCS Actuation</u>

The ECCS Actuation Reactor Trip function ensures that if a Reactor Trip has not already been generated by the RTS, the ESFAS Automatic Actuation Logic will initiate a Reactor Trip upon any signal that initiates ECCS Actuation. This is a condition of acceptability for the loss of coolant accident (LOCA). However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a Reactor Trip is initiated every time an ECCS Actuation signal is present.

Nominal Trip Setpoint and Allowable Values are not applicable to this Function. The ECCS Actuation signals are provided within the RPS. Therefore, there is no measurement signal with which to associate an LSSS.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires three trains of ECCS Actuation to be OPERABLE in MODE 1 or 2.

A Reactor Trip is initiated every time an ECCS Actuation signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

15. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure Reactor Trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated Reactor Trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux Reactor Trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed,

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux Reactor Trip, and

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- on increasing power, the P-6 interlock provides a backup block signal to the source range flux doubling circuit. Normally, this Function is manually blocked by the control room operator during the reactor startup.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux Reactor Trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine Inlet Pressure, P-13 interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables Reactor Trips on the following Functions:

- Low Pressurizer Pressure,
- High Pressurizer Water Level,
- Low Reactor Coolant Flow,
- Low RCP Speed,
- High Steam Generator (SG) Water Level,
- Turbine Trip - Turbine Emergency Trip Oil Pressure, and
- Turbine Trip - Main Turbine Stop Valve Position.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These Reactor Trips are only required when operating above the P-7 setpoint (approximately 10% power). The Reactor Trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks Reactor Trips on the following Functions:

- Low Pressurizer Pressure,
- High Pressurizer Water Level,
- Low Reactor Coolant Flow,
- Low RCP Speed,
- High Steam Generator (SG) Water Level,
- Turbine Trip - Turbine Emergency Trip Oil Pressure, and
- Turbine Trip - Main Turbine Stop Valve Position.

Nominal Trip Setpoint and Allowable Value are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS.
The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires the Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in each OPERABLE RTS train in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux Reactor Trip. Note that blocking the Reactor Trip also blocks the signal to prevent automatic and manual rod withdrawal,
- on increasing power, the P-10 interlock allows the operator to manually block the High Power Range Neutron Flux (Low Setpoint) Reactor Trip,
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux Reactor Trip, and also to de-energize the NIS source range detectors,
- the P-10 interlock provides one of the two inputs to the P-7 interlock, and
- on decreasing power, the P-10 interlock automatically enables the High Power Range Neutron Flux (Low Setpoint) Reactor Trip and the Intermediate Range Neutron Flux Reactor Trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the High Power Range Neutron Flux (Low Setpoint) and High Intermediate Range Neutron Flux Reactor Trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux Reactor Trip provides core protection.

d. <u>Turbine Inlet Pressure, P-13</u>

The Turbine Inlet Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by two-out-of-four pressure detectors. The LCO requirement for this Function ensures that three of the inputs to the P-7 interlock are available.

The LCO requires three channels of Turbine Inlet Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine Inlet Chamber Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

16. <u>Reactor Trip Breakers</u>

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires three OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train consists of two main breakers. Three OPERABLE trains ensure no single random failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 19 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

18. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 16 and 17) and Automatic Trip Logic (Function 18) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. The Reactor Trip signals generated by the RTS Automatic Trip Logic cause the RTBs to open and shut down the reactor.

The LCO requires three trains of RTS Automatic Trip Logic to be OPERABLE. Having three OPERABLE trains ensures that random failure of a single logic train will not prevent Reactor Trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 8).

ACTIONS

A Note has been added to 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 3.3.1-1.

In the event a channel's accuracy is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or digital bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceeds those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

In all cases where the LCO states "Restore channel or train to OPERABLE status", this means restore the required number of channels or trains to OPERABLE status. Therefore, restoration of an alternate channel or train, other than the failed channel or train, is also acceptable.

A.1

Condition A applies to all RTS protection Functions.

Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation for this Function. With one required train inoperable, the inoperable train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining two OPERABLE trains are adequate to perform the safety function.

ACTIONS (continued)

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 72 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (78 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems.

With the unit in MODE 3, ACTION C would apply to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The Completion Time of 72 hours is justified because two trains are adequate to perform the safety function , and there are three automatic actuation trains and two other Manual Reactor Trip trains OPERABLE. In addition, the Completion Time considers that the Manual Reactor Trip Function, for the inoperable Manual Reactor Trip Function, can be actuated from the Safety VDU for that train. Therefore, the ability to initiate a manual Reactor Trip through safety related equipment remains functional in all three trains.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

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

Condition C applies to the Manual Reactor Trip Function in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

BASES

ACTIONS (continued)

This action addresses the train orientation for this Function. With one required train inoperable, the inoperable train must be restored to OPERABLE status within 72 hours. If the affected Function cannot be restored to OPERABLE status within the allowed 72 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 72 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, this Function is no longer required.

The Completion Time of 72 hours is justified because two trains are adequate to perform the safety function, and there are three automatic actuation trains and two other Manual Reactor Trip Functions OPERABLE. In addition, the Completion Time considers that the Manual Reactor Trip Function, for the inoperable Manual Reactor Trip train, can be actuated from the Safety VDU for that train. Therefore, the ability to initiate a manual Reactor Trip through safety related equipment remains functional in all three trains.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19(Ref. 10).

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

Condition D applies to the following Reactor Trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted:

- RTBs,
- RTB Undervoltage and Shunt Trip Mechanisms, and
- Automatic Trip Logic.

BASES

ACTIONS (continued)

This action addresses the train orientation for these Functions. With one required train inoperable, the inoperable train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time of 48 hours is justified because the two remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE trains each have continuous automatic self-testing for the Automatic Trip Logic.

The Completion Time of 48 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

E.1.1, E.1.2, E.2.1, E.2.2, and E.3

Condition E applies to the Power Range Neutron Flux (High Setpoint) Function.

With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. This results in a partial trip condition requiring only one-out-of-three logic for actuation of the two-out-of-four trips.

The Completion Time of 72 hours to place the inoperable channel in the trip condition is justified because the three remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the three remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS. In addition, with the remaining three OPERABLE channels, the SSA within the PCMS ensures the control

BASES

ACTIONS (continued)

systems can withstand an input failure to the control system without causing erroneous control system operation, which would otherwise require the protection function actuation.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

In addition to placing the inoperable channel in the trip condition, THERMAL POWER must be reduced to ≤ 75% RTP within 78 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above Required Actions, the inoperable channel can be placed in the trip condition within 72 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels < 75% RTP. The 12 hour Surveillance Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Required Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the plant in MODE 3. The 78 hour Completion Time includes 72 hours for channel corrective maintenance and an additional 6 hours for the MODE reduction as required by Required Action E.3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing surveillance testing, or setpoint adjustments when a setpoint reduction is required by other Technical Specifications, provided the other channels are OPERABLE, or two channels are OPERABLE and one is placed in the trip condition. With one channel bypassed, the system can detect all anomalies, but it cannot also sustain a single failure.

BASES

ACTIONS (continued)

The Bypass Time of 12 hours is justified because the remaining OPERABLE channels are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Bypass Time of 12 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

Required Action E.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors once per 12 hours may not be necessary.

F.1 and F.2

Condition F applies to the following Reactor Trip Functions:

- High Power Range Neutron Flux (Low Setpoint),
- High Power Range Neutron Flux Rate (Positive Rate), and
- High Power Range Neutron Flux Rate (Negative Rate).

ACTIONS (continued)

With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. Placing the channel in the trip condition results in a partial trip condition requiring only one-out-of-three logic for actuation of the two-out-of-four trips.

The Completion Time of 72 hours to place the inoperable channel in the trip condition is justified because the three remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the three remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

In addition, with the remaining three OPERABLE channels, the SSA within the PCMS ensures the control systems can withstand an input failure to the control system without causing erroneous control system operation, which would otherwise require the protection function actuation.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours are allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing surveillance testing, provided the other channels are OPERABLE, or two channels are OPERABLE and one is placed in the trip condition. With one channel bypassed, the system can detect all anomalies, but it cannot also sustain a single failure.

The Bypass Time of 12 hours is justified because the remaining OPERABLE channels are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Bypass Time of 12 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

ACTIONS (continued)

G.1 and G.2

Condition G applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint, and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 24 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint.

The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required.

The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel.

This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in Reactor Trip.

H.1 and H.2

Condition H applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in Reactor Trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions.

With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power

ACTIONS (continued)

level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint.

Required Action H.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action I.1 is modified by a Note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

K.1, K.2.1, and K.2.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS

ACTIONS (continued)

source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour.

L.1 and L.2

Condition L applies to the following Reactor Trip Functions:

- Low Reactor Coolant Flow,
- Low Reactor Coolant Pump Speed, and
- Turbine Trip – Turbine Emergency Trip Oil Pressure.

With one required channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours. Failure of one channel places the Function in a two-out-of-two configuration, when the failed channel does not result in a trip channel. This configuration provides adequate plant protection, but does not meet the single failure criteria. Therefore, within 72 hours the inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies the single failure criteria. Placing the channel in the trip condition when above the P-7 setpoint, results in a partial trip condition requiring only one additional channel to initiate a Reactor Trip.

These Functions do not have to be OPERABLE below the P-7 setpoint because there is insufficient heat production to generate DNB conditions below the P-7 setpoint.

BASES

ACTIONS (continued)

The Completion Time of 72 hours to place the inoperable channel in the trip condition is justified because the two remaining OPERABLE channels are adequate to perform the safety function. The Completion Time also considers that the two remaining OPERABLE channels have continuous automatic self-testing.

In addition, the two remaining OPERABLE channels have continuous automatic CHANNEL CHECKS, except for Turbine Trip – Turbine Emergency Trip Oil Pressure. This additional justification is not needed for Turbine Trip – Turbine Emergency Trip Oil Pressure, because this is an anticipatory function that is not credited in the safety analysis.

For all functions (except Turbine Trip – Turbine Emergency Trip Oil Pressure), the Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

The Required Actions are modified by a Note that allows placing one required channel in bypass for up to 12 hours while performing surveillance testing, provided the other required channels are OPERABLE, or one required channel is OPERABLE and the other required channel is placed in the trip condition. With one required channel bypassed, the system can detect all anomalies, but it cannot also sustain a single failure.

ACTIONS (continued)

The Bypass Time of 12 hours is justified because the remaining OPERABLE channels are adequate to perform the safety function. The Bypass Time also considers that the remaining OPERABLE channels have continuous automatic self-testing.

In addition the remaining OPERABLE channels have continuous automatic CHANNEL CHECKS, except for Turbine Trip – Turbine Emergency Trip Oil Pressure. This additional justification is not needed for Turbine Trip – Turbine Emergency Trip Oil Pressure, because this is an anticipatory function that is not credited in the safety analysis.

The Bypass Time of 12 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

M.1 and M.2

Condition M applies to the ECCS Actuation input in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one required train inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours.

The Completion Time of 24 hours is justified because the two remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE trains each have continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing one required train in bypass for up to 4 hours while performing surveillance testing, provided the other required trains are OPERABLE.

BASES

ACTIONS (continued)

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

N.1 [and N.2]

Condition N applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one required train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the two remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE trains each have continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

[Required Action N.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

O.1 and O.2

Condition O applies to the P-6 and P-10 interlocks. With one or more channels inoperable, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function.

The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

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The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

P.1 and P.2

Condition P applies to the P-7 and P-13 interlocks in MODE 1. With one or more required channels inoperable (P-13), or one or more trains inoperable (P-7), the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function.

The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

The Completion Time of 1 hour is required because the P-13 interlock is generated using the Turbine Inlet Pressure instrumentation channels, which are shared with the PCMS. The SSA within the PCMS prevents erroneous control system actions due to a single failed shared instrument channel, which would otherwise require the protection function actuation. When there are less than three OPERABLE required Turbine Inlet Pressure instrumentation channels, the SSA cannot prevent erroneous control system operation due to an input failure.

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

Q.1 [and Q.2]

Condition Q applies to the RTB Undervoltage and Shunt Trip Mechanisms, i.e., diverse trip features, in MODES 1 and 2. For either of the two RTBs in a required train, with one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours.

The Completion Time of 48 hours for Required Action Q.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, one OPERABLE RTB in the affected RTB train and two OPERABLE RTB trains capable of performing the safety function.

BASES

ACTIONS (continued)

The Completion Time of 48 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

[Required Action Q.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

R.1 [and R.2]

Condition R applies to the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one required train inoperable, 24 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the two remaining OPERABLE required trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE required trains each have continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

[Required Action R.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

The Required Actions have been modified by a Note that allows placing one required train in bypass for up to 4 hours while performing surveillance testing, provided the other required trains are OPERABLE.

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

BASES

ACTIONS (continued)

S.1

Condition S applies when the Required Action and associated Completion Time for Condition N, Q, or R have not been met. If the train cannot be returned to OPERABLE status, the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within 6 hours. The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

Placing the unit in MODE 3, with any of the applicable Functions inoperable, results in Condition D entry.

T.1 and T.2

Condition T applies to Main Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 12 hours. If placed in the trip condition, this results in a partial trip condition requiring three additional channels to initiate a Reactor Trip. If the channel can not be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-7 setpoint within the next 6 hours. The 6 hours allowed for reducing power are consistent with other power reduction action Completion Times.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing surveillance testing.

The Completion Time and Bypass Time are justified because this is an anticipatory trip that is not credited in the safety analysis, and a diverse Turbine Trip is also initiated from the Turbine Emergency Oil Pressure.

BASES

ACTIONS (continued)

U.1 and U.2

Condition U applies to the following Reactor Trip Functions:

- Overtemperature ΔT,
- Overpower ΔT,
- High Pressurizer Pressure, and
- Low SG Water Level.

With one required channel inoperable, the inoperable channel must be placed in the trip condition within 1 hour and restored to OPERABLE status in 72 hours.

This Condition applies to functions that operate on two-out-of-three logic and have channels that are shared with the control systems. Normally the SSA can prevent erroneous control system operations. However, when there are less than three OPERABLE required channels, the SSA cannot prevent erroneous control system operation due to an input failure. With two OPERABLE required channels and one required channel in the trip condition, if a channel failure occurs in an OPERABLE required channel and results in erroneous control system operation, the remaining OPERABLE required channel can provide a plant trip. However, the channel that causes the erroneous control system operation cannot be credited as the single failure; therefore, this configuration does not satisfy the single failure criteria. To satisfy the single failure criteria, three required channels must be restored to OPERABLE status within 72 hours.

The Completion Time of 1 hour to place the failed channel in the trip condition is based on operating experience and the minimum amount of time allowed for manual operator actions.

The Completion Time of 72 hours to restore the inoperable channel is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic channel checks.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref.10).

Bypass of a required channel is not allowed because there are only three required channels and these channels are also used for control. If a failure were to occur in one of the two remaining required control channels, a plant transient could occur that would require a plant trip, but a plant trip would not occur with only one remaining OPERABLE required channel.

V.1

If the Required Action and associated Completion Time of Condition U is not met, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours are allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

W.1 and W.2

Condition W applies to the following Reactor Trip Functions:

- Low Pressurizer Pressure,
- High Pressurizer Water Level, and
- High-High SG Water Level.

With one required channel inoperable, the inoperable channel must be placed in the trip condition within 1 hour and restored to OPERABLE status in 72 hours.

This Condition applies to functions that operate on two-out-of-three logic and have channels that are shared with the control systems. Normally the SSA can prevent erroneous control system operations. However, when there are less than three OPERABLE required channels, the SSA cannot prevent erroneous control system operation due to an input failure. With two OPERABLE required channels and one required channel in the trip condition, if a channel failure occurs in an OPERABLE required channel and results in erroneous control system operation, the remaining OPERABLE required channel can provide a plant trip. However, the channel that causes the erroneous control system operation cannot be credited as the single failure; therefore, this configuration does not satisfy the single failure criteria. When above the P-7 setpoint, to satisfy the single failure criteria, three channels must be restored to OPERABLE status within 72 hours.

ACTIONS (continued)

These Functions do not have to be OPERABLE below the P-7 setpoint because there is insufficient heat production to generate DNB conditions below the P-7 setpoint.

The Completion Time of 1 hour to place the failed channel in the trip condition is based on operating experience and the minimum amount of time allowed for manual operator actions.

The Completion Time of 72 hours to restore the inoperable channel is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref.10).

Bypass of a required channel is not allowed because there are only three required channels and these channels are also used for control. If a failure were to occur in one of the two remaining required control channels, a plant transient could occur that would require a plant trip, but a plant trip would not occur with only one remaining OPERABLE required channel.

X.1

If the Required Action and associated Completion Time of Condition W is not met, the unit must be placed in which THERMAL POWER is below P-7. Six hours are allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

The Completion Time of 6 hours is reasonable, based on operating experience, to reduce THERMAL POWER to below P-7 from full power in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies all trains of the RTS. However, when testing a Channel, it is only necessary to manually verify that the channel is OPERABLE in its respective train. This is because the interface to other trains is continuously verified through continuous automatic self-testing. Continuous automatic self-testing is confirmed through periodic MIC. The CHANNEL CALIBRATION is performed in a manner that is consistent with the methods and assumptions of Specification 5.5.21, Setpoint Control Program (SCP).

SR 3.3.1.1

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

Agreement criteria are determined based on a combination of the channel instrument uncertainties. 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.

[The Surveillance Frequency of 12 hours is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SURVEILLANCE REQUIREMENTS (continued)

A CHANNEL CHECK may be conducted manually or automatically. For the US-APWR an automated CHANNEL CHECK is normally conducted continuously, which satisfies the 12 hour Surveillance Frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria is not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum 12 hour Surveillance Frequency.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.1.2</u>

SR 3.3.1.2 compares the calorimetric heat balance calculation to the power range channel output. If the calorimetric heat balance calculation results exceed the power range channel output by more than 2% RTP, the power range channel is not declared inoperable, but must be adjusted. The power range channel output shall be adjusted consistent with the calorimetric heat balance calculation results if the calorimetric calculation exceed the power range channel output by more than + 2% RTP. If the power range channel output cannot be properly adjusted, the channel is declared inoperable.

If the calorimetric is performed at part power (<70% RTP), adjusting the power range channel indication in the increasing power direction will assure a Reactor Trip below the safety analysis limit (<118% RTP). Making no adjustment to the power range channel in the decreasing power direction due to a part power calorimetric assures a Reactor Trip consistent with the safety analyses.

SURVEILLANCE REQUIREMENTS (continued)

This allowance does not preclude making indicated power adjustments, if desired, when the calorimetric heat balance calculation is less than the power range channel output. To provide close agreement between indicated power and to preserve operating margin, the power range channels are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric (< 70% RTP). This action may introduce a non-conservative bias at higher power levels which may result in an NIS Reactor Trip above the safety analysis limit (> 118% RTP). The cause of the potential non-conservative bias is the decreased accuracy of the calorimetric at reduced power conditions. The primary error contributor to the instrument uncertainty for a secondary side power calorimetric measurement is the feedwater flow measurement, which is typically a ΔP measurement across a feedwater venturi. While the measurement uncertainty remains constant in ΔP as power decreases, when translated into flow, the uncertainty increases as a square term.

Thus a 1% flow error at 100% power can approach a 10% flow error at 30% RTP even though the ΔP error has not changed. An evaluation of extended operation at part power conditions would conclude that it is prudent to administratively adjust the digital setpoint of the High Power Range Neutron Flux (High Setpoint) digital bistables to ≤ 85% RTP when: 1) the power range channel output is adjusted in the decreasing power direction due to a part power calorimetric below 70% RTP; or 2) for a post refueling startup. The evaluation of extended operation at part power conditions would also conclude that the potential need to adjust the indication of the High Power Range Neutron Flux in the decreasing power direction is quite small, primarily to address operation in the intermediate range about P-10 (nominally 10% RTP) to allow enabling of the High Power Range Neutron Flux (Low Setpoint) and the Intermediate Range Neutron Flux Reactor Trips. Before the High Power Range Neutron Flux (High Setpoint) digital bistables are reset to ≤ 109% RTP, the power range channel adjustment must be confirmed based on a calorimetric performed at ≥ 70% RTP.

The Note clarifies that this SR is required only if reactor power is ≥ 15% RTP and that 12 hours are allowed for performing the first SR after reaching 15% RTP. A power level of 15% RTP is chosen based on plant stability, i.e., automatic rod control capability and turbine generator synchronized to the grid.

SURVEILLANCE REQUIREMENTS (continued)

[The Surveillance Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate that a difference between the calorimetric heat balance calculation and the power range channel output of more than +2% RTP is not expected in any 24 hour period.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. The excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This SR is performed to verify the f(ΔI) input to the Overtemperature ΔT Function and Overpower ΔT Function.

A Note clarifies that the SR is required only if reactor power is ≥ 15% RTP and that 24 hours are allowed for performing the first SR after reaching 15% RTP.

[The Surveillance Frequency of every 31 effective full power days (EFPD) is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT. This test shall verify RTB train OPERABILITY by actuation of the two RTBs for each train to their trip state. Each RTB may be actuated together or individually.

The RTB train test shall include three separate but overlapping tests: (1) The Undervoltage test for verification of RTB operability using only the Undervoltage Trip Mechanism, (2) The Shunt Trip test for verification of RTB operability using only the Shunt Trip Mechanisms, and (3) The Manual Reactor Trip test for verification of RTB operability using the hardwired switches. The Undervoltage test shall bypass the Shunt Trip Mechanism, so each RTB actuates using only the Undervoltage Trip Mechanism. The Shunt Trip test shall bypass the Undervoltage Trip Mechanism, so each RTB actuates using only the Shunt Trip Mechanism. The Manual Reactor Trip test shall actuate the RTB with both mechanisms. Figure 4.4-1 of MUAP-07004 (Ref. 6) describes an acceptable overlapping method for conducting these three separate tests that confirms OPERABLE status.

[The Surveillance Frequency of every 62 days on a STAGGERED TEST BASIS applies to all four RTB trains. This Surveillance Frequency is justified based on industry experience. The Surveillance Frequency also considers the added reliability of the US-APWR RTB configuration, which includes redundant RTBs within each train and the overall two-out-of-four train configuration. Since each test actuates each RTB to its required trip state, the STAGGERED TEST BASIS results in each RTB being tested every 248 days, and each tripping method being tested every 744 days.

The TADOT STAGGERED TEST BASIS Surveillance Frequency of 62 days, with each RTB tested every 248 days, and each trip method ultimately tested every 744 days, is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

BASES

SURVEILLANCE REQUIREMENTS (continued)

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.1.5

SR 3.3.1.5 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This SR is performed to verify the f(ΔI) input to the Overtemperature ΔT Function and Overpower ΔT Function.

A Note modifies SR 3.3.1.5. The Note states that this SR is required only if reactor power is > 50% RTP and that 24 hours are allowed for performing the first SR after reaching 50% RTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The Surveillance Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.1.6

SR 3.3.1.6 is the performance of a MIC for the RTS Instrumentation. This includes the RPS.

The PSMS is self-tested automatically on a continuous basis from the digital side of all input modules to the digital side of all output modules. Continuous automatic self-testing encompasses all PSMS safety-related functions including digital Nominal Trip Setpoints, Time Constants and actuation logic functions. The continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. The continuous automatic self-testing is described in Reference 6 and Reference 7.

The MIC is a diverse check of the PSMS software memory integrity, consistent with the Setpoint Control Program (SCP), to ensure there is no change to the internal PSMS software that would impact its functional operation, including digital Nominal Trip Setpoints, Time Constants, actuation logic functions or the continuous automatic self-testing. The MIC is described in Reference 6 and Reference 7.

The capability to generate continuous automatic self-testing fault alarms shall be confirmed OPERABLE during the MIC.

SURVEILLANCE REQUIREMENTS (continued)

The complete OPERABILITY check from the measurement channel input device to the Reactor Trip Breaker is performed by the combination of the continuous automatic self-testing for the digital devices (the RPS and data communication interfaces), the continuous automatic CHANNEL CHECK (SR 3.3.1.1 and SR 3.3.1.7), the CHANNEL CALIBRATION (SR 3.3.1.8, SR 3.3.1.9 and SR 3.3.1.10), the MIC (SR 3.3.1.6) and the TADOT (SR 3.3.1.4 and SR 3.3.1.11). The CHANNEL CALIBRATION, the MIC and the TADOT, which are manual tests, overlap with the continuous automatic self-testing and confirm the functioning of the continuous automatic self-testing.

[The Surveillance Frequency of 24 months is justified because the software memory integrity is checked by the continuous automatic self-testing.

The Surveillance Frequency of 24 months is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 10).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.1.7</u>

Performance of the CHANNEL CHECK within 4 hours after reducing power below P-6 and [once every 12 hours thereafter OR in accordance with the Surveillance Frequency Control Program] ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the

SURVEILLANCE REQUIREMENTS (continued)

same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Surveillance Frequency of 4 hours is based on the need to verify OPERABILITY of the SR instruments within a reasonable time after being re-energized.

[The 12 hour Surveillance Frequency thereafter is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

A CHANNEL CHECK may be conducted manually or automatically. For the US-APWR an automated CHANNEL CHECK is normally conducted continuously, which satisfies the 12 hour Surveillance Frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria is not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum 12 hour Surveillance Frequency.

OR The Surveillance Frequency thereafter is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.1.8

SR 3.3.1.8 is the performance of a CHANNEL CALIBRATION.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test must be performed consistent with the methods and assumptions of Specification 5.5.21, SCP, to verify that the

SURVEILLANCE REQUIREMENTS (continued)

channel responds to a measured parameter within the necessary range and accuracy.

The CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital VDU readout as described in Reference 6.

For analog measurements, the CHANNEL CALIBRATION confirms the calibration settings are within the Allowable Value at multiple points over the entire measurement channel span, encompassing all Reactor Trip and interlock Nominal Trip Setpoint values. Digital Reactor Trip and interlock Nominal Trip Setpoint values are confirmed through a MIC.

For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel's state change. The state change must occur within the Allowable Value of the Nominal Trip Setpoint.

The equipment that performs the automated CHANNEL CHECK shall be confirmed OPERABLE, including the capability to generate fault alarms during the CHANNEL CALIBRATION.

[The Surveillance Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with Specification 5.5.21, Setpoint Control Program (SCP).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.9

SR 3.3.1.9 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.8, for the neutron flux channels. This SR is modified by a Note stating that the neutron detectors are excluded from the CHANNEL CALIBRATION.

For this SR the calibration for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. For this SR the calibration for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This SR is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors.

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

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.1.10

SR 3.3.1.10 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.8. CHANNEL CALIBRATION is accomplished by a cross calibration that compares the signals from the installed channels to a channel with a reference RTD, in accordance with FSAR Section 7.1.3.14 (Ref. 13).

SURVEILLANCE REQUIREMENTS (continued)

The rate lag compensation for flow from the core to the RTDs is implemented in the RPS through digital functions; this rate lag function is confirmed through the MIC, SR 3.3.1.6.

[The Surveillance Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with Specification 5.5.21, Setpoint Control Program (SCP).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.1.11</u>

SR 3.3.1.11 is the performance of a TADOT of Turbine Trip Functions. This TADOT is performed prior to exceeding the P-7 interlock whenever the unit has been in MODE 3. This SR is not required if it has been performed within the previous 31 days. Verification of the Nominal Trip Setpoint is not performed during the TADOT SR; the Nominal Trip Setpoint is verified during CHANNEL CALIBRATION. Performance of this test will ensure that the Turbine Trip Function is OPERABLE prior to exceeding the P-7 interlock.

<u>SR 3.3.1.12</u>

SR 3.3.1.12 verifies that the RTS RESPONSE TIME is less than or equal to the maximum values assumed in the accident analysis. Accident analysis response time values are specified in Reference 2. Individual component response times are not modeled in the analyses.

The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Analytical Limit to the point at which the equipment reaches the required functional state (i.e., control and shutdown rods fully inserted in the reactor core).

SURVEILLANCE REQUIREMENTS (continued)

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel.

Allocations for sensors, signal processing and actuation logic response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications.

The PSMS MELTAC controllers employ dynamic transfer functions with Time Constants that are installed as digital values and processed through digital algorithms. Therefore, the time response of all digital PSMS functions has no potential for variation due to time, environmental drift or component aging.

PSMS Time Constants are set at the nominal values assumed in the safety analysis. The combination of continuous automatic self-testing and MIC confirms the integrity of the dynamic transfer functions, Time Constants and actuation logic functions.

The response time for the digital portion of the PSMS is determined one time by analysis and confirmed one time in the factory test. Therefore, for PSMS digital functions, including Functions with Time Constants, response time tests are not required; instead, a response time allocation may be applied.

Response time for PSMS MELTAC input signal conditioning, can be affected by random failures or degradation, which can be detected by CHANNEL CALIBRATION. Section 4.6 of MUAP-07005, “Safety System Digital Platform -MELTAC-” (Ref. 7) describes the basis for crediting CHANNEL CALIBRATION for detecting PSMS signal conditioning response time degradation. Therefore, for PSMS input signal conditioning, response time tests are not required; instead, a response time allocation may be applied.

BASES

SURVEILLANCE REQUIREMENTS (continued)

MUAP-09021-P, "Response Time of Safety I&C System" (Ref. 11), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the report. Response time verification for other sensor types must be demonstrated by test. MUAP-09021-P also provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time.

In addition, MUAP-09021-P identifies the acceptance criteria for RTS components that require response time measurement (such as RTBs and RTDs which are known to have aging or wear-out mechanisms that can impact response time), taking into consideration the total RTS RESPONSE TIME requirement and the allocations for other components that do not require testing.

The allocations for sensor, signal conditioning and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

SURVEILLANCE REQUIREMENTS (continued)

[As appropriate, each channel's response must be verified every 24 months on a STAGGERED TEST BASIS. Testing of the final actuation devices (i.e., RTBs) is included in the testing. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this SR when performed at the 24 months Surveillance Frequency. Therefore, the Surveillance Frequency was concluded to be acceptable from a reliability standpoint. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.1.12 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety Related Instrumentation."
2. FSAR Section 7.2.
3. FSAR Chapter 15.
4. IEEE-603-1991.
5. 10 CFR 50.49.
6. MUAP-07004-P, Revision 7, “Safety I&C System Description and Design Process.”
7. MUAP-07005-P, Revision 8, “Safety System Digital Platform -MELTAC-.”
8. 10 CFR 50.36.
9. FSAR Section 6.2.1.
10. FSAR Chapter 19.
11. MUAP-09021-P, Revision 3, “Response Time of Safety I&C System.”
12. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”
13. FSAR Section 7.1

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Features Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into four distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured,
- The Reactor Protection System (RPS) provides signal conditioning, analog to digital conversion, digital bistables for setpoint comparison, process algorithm actuation, digital output to the ESFAS, and digital output to control board/Main Control Room (MCR)/miscellaneous VDUs,
- The ESFAS and Safety Logic System (SLS) provides Actuation Logic, and Actuation Outputs to initiate the proper unit shutdown or Engineered Safety Features (ESF) actuation in accordance with the defined logic, based on the partial actuation inputs from the RPS, and
- The Safety VDUs (S-VDU) and Communication Subsystems (COM) provide Manual Control of ESF Components and backup manual initiation of Reactor Trip and ESFAS Functions.

The Nominal Trip Setpoint, recorded and maintained in a document established by the Setpoint Control Program (SCP), is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the Nominal Trip Setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the Nominal Trip Setpoint plays an important role in ensuring that SLs are not exceeded. As such, the Nominal Trip Setpoint meets the definition of an LSSS (Ref. 13) and is used to meet the requirement that they be contained in the Technical Specifications. This is an acceptable approach for digital systems because the digital setpoints do

BASES

BACKGROUND (continued)

not drift as in analog systems. The Nominal Trip Setpoint is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

Technical Specifications contain Allowable Values related to the OPERABILITY of equipment required for safe operation of the facility. The Allowable Value accommodates expected drift in the analog components of the channel that would have been specifically accounted for in the setpoint methodology for calculating the Nominal Trip Setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as-found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to recalibrate the device to account for further drift during the next surveillance interval.

However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value.

The Allowable Value, in conjunction with the Nominal Trip Setpoint and LCO, establishes the threshold for ESFAS action to prevent exceeding acceptable limits such that the consequences of Postulated Accidents (PAs) will be acceptable. The Allowable Value, recorded and maintained in a document established by the Setpoint Control Program (SCP), is considered a limiting value such that a channel is OPERABLE if the as-found value does not exceed the Allowable Value during CHANNEL CALIBRATION. The Allowable Value is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

For analog measurements, the CHANNEL CALIBRATION verifies the channel accuracy at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range. For binary measurements, the CHANNEL CALIBRATION verifies the accuracy of the channel’s state change at the required setpoint. As such, the Allowable Value accounts for the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a SL is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval.

BACKGROUND (continued)

Note that, although the channel is "OPERABLE" under these circumstances, the channel shall be left adjusted to a value within the established channel Calibration Tolerance (CT) band in accordance with the uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. The Calibration Tolerance, recorded and maintained in a document established by the SCP, is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

If the as-found value of the device is found to have exceeded the Allowable Value, or the as-left value of the device cannot be adjusted to a value within the Calibration Tolerance, the device would be considered inoperable from a technical specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

In the Protection and Safety Monitoring System (PSMS), setpoints associated with analog measurements are stored as digital values that have no potential for variation due to time, environmental drift or component aging. For analog measurements, the only factors that can result in variation in the trip functions reside in the uncertainties that are pertinent to the analog portion of the system. Therefore, for analog measurements in the PSMS, it is appropriate for the Allowable Value to be expressed in terms of values that are measured during periodic testing of the analog portion of the system (i.e., CHANNEL CALIBRATION).

For PSMS analog measurements, the as-found and as-left values are measured from sensor to digital Visual Display Unit (VDU) readout during CHANNEL CALIBRATION. The US-APWR enhances human performance by establishing a standard CHANNEL CALIBRATION method for all analog measurements, whereby the as-found and as-left values read at the VDU are measured at the same five calibration settings, regardless of the PSMS trip setpoint(s).

Since the PSMS trip logic and setpoints for analog measurements are stored as digital values with no drift potential, and those digital values are confirmed through the MEMORY INTEGRITY CHECK (MIC), the only untested area required to confirm channel operability pertains to the accuracy of the analog input signal. When the analog input accuracy is confirmed, by reading the digital values of the five point CHANNEL CALIBRATION settings on any VDU driven by the same digital value used in the controller that executes the trip functions, the operability of the complete channel is confirmed, including the accuracy of all trip setpoints associated with that channel.

BASES

BACKGROUND (continued)

In the PSMS, setpoints associated with binary measurements are stored within the binary device itself. These setpoints have potential for variation due to time, environmental drift or component aging. However, these sensors are interfaced to the digital portion of the PSMS, which has no potential for variation due to time, environmental drift or component aging. For binary measurements, the only factors that can result in variation in the trip functions reside in the uncertainties that are pertinent to the binary sensor itself. Therefore, for binary measurements in the PSMS, it is appropriate for the Allowable Value to be expressed in terms of values that are measured during periodic testing of the binary device (i.e., CHANNEL CALIBRATION).

For PSMS binary measurements, the as-found and as-left state change values are measured from sensor to VDU readout during CHANNEL CALIBRATION. The US-APWR enhances human performance by establishing a standard CHANNEL CALIBRATION method for all binary measurements, whereby the as-found and as-left values read at the VDU are measured at the channel's required state change.

Since the PSMS trip logic for binary sensors is stored as digital values with no drift potential, and those digital values are confirmed through the MIC, the only untested area required to confirm channel operability pertains to the accuracy of the binary input signal. When the binary input accuracy is confirmed, by reading the channel's state change on any VDU driven by the same digital value used in the controller that executes the trip functions, the operability of the complete channel is confirmed, including the accuracy of the trip setpoint associated with that channel.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by "as-found" calibration data evaluated during the CHANNEL CALIBRATION and by qualitative assessment of field transmitter or sensor, as related to the channel behavior observed during performance of the CHANNEL CHECK.

BACKGROUND (continued)

Protection and Safety Monitoring System

Generally, four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, analog to digital conversion, comparable digital output signals for VDUs located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are recorded and maintained in a document established by the Setpoint Control Program (SCP). If the measured value of a unit parameter exceeds the predetermined setpoint, a digital output from a digital bistable is forwarded to the ESFAS for decision evaluation. Channel separation is maintained throughout the PSMS. Some unit parameters provide input only to the PSMS, while others are used by the PSMS and are retransmitted to the Plant Control and Monitoring System (PCMS) for use in one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the protection circuits and a control function, three channels with a two-out-of-three logic are also sufficient to provide the required reliability and redundancy. When three or more channels are OPERABLE, the Signal Selection Algorithm (SSA) within the PCMS ensures the control systems can withstand an input failure to the control system without causing erroneous control system operation which would otherwise require the protection function actuation. Since the input failure does not cause an erroneous control system action that challenges the protection function, the input failure is considered a single failure in the ESFAS and the ESFAS remains capable of providing its protective function with the remaining two OPERABLE channels. Again, a single failure will neither cause nor prevent the protection function actuation. When there are less than three OPERABLE channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared channels, when there are only three required channels.

These requirements are described in IEEE-603-1991 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

BASES

BACKGROUND (continued)

Allowable Values and ESFAS Setpoints

The Nominal Trip Setpoints used in the digital bistables or binary sensors are based on the Analytical Limits defined in the accident analysis and the channel uncertainty. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing Time Delays are taken into account.

To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values and Nominal Trip Setpoints are conservative to protect the Analytical Limits. The methodology identified in the SCP, used to calculate the Allowable Values and Nominal Trip setpoints, incorporates all of the known uncertainties applicable to each channel (Ref. 12). The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint and Allowable Value.

The Nominal Trip Setpoint entered into the bistable or binary sensor is more conservative than that specified by the Analytical Limit. The Nominal Trip Setpoint accounts for measurement errors detectable by the CHANNEL CALIBRATION and other unmeasurable errors (such as the effects of anticipated environmental conditions), which are both considered in the Allowable Value for CHANNEL CALIBRATION. The Allowable Value serves as the Technical Specification OPERABILITY limit for the purpose of the CHANNEL CALIBRATION. One example of such a change in measurement error is drift during the surveillance interval. If the as-found value does not exceed the Allowable Value, the channel is considered OPERABLE.

The Nominal Trip Setpoint (i.e., LSSS) is the value at which the digital bistable or binary sensor is set. The Nominal Trip Setpoint value ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any channel is considered to be properly adjusted when the "as-left" value is within the established Calibration Tolerance (CT) band in accordance with the methods and assumptions of the SCP. The Nominal Trip Setpoint value (i.e., expressed as a value without inequalities) for digital bistables, is confirmed during the MIC. The Nominal Trip Setpoint value (i.e., expressed as a value with inequalities) for binary sensors is confirmed during the CHANNEL CALIBRATION.

BASES

BACKGROUND (continued)

Nominal Trip Setpoints and Allowable Values, consistent with the requirements of the SCP, ensure that SLs are not violated during AOOs and that the consequences of PAs will be acceptable, provided the unit is operated from within the LCOs at the onset of the PA and the equipment functions as designed.

Within the PSMS controllers, Nominal Trip Setpoints, Time Constants and Time Delays are digital settings maintained in non-volatile software memory within each RPS train. Digital settings have no potential for variation due to time, environmental drift or component aging; therefore, these digital settings have no surveillance tolerance. Each PSMS controller has continuous automatic self-testing, which verifies that the digital Nominal Trip Setpoint and Time Constant settings are correct. Nominal Trip Setpoints and Time Constants are also verified periodically through the MIC which must be conducted with the affected PSMS controller out of service. A designated instrument channel is taken out of service for periodic CHANNEL CALIBRATION. SRs for the channels and trains are specified in the SR section.

The Allowable Value is the maximum deviation that can be measured during CHANNEL CALIBRATION, whereby the channel is considered OPERABLE. This value includes the deviations that are included in the calculations that determined the Nominal Trip Setpoint. The “expected as-found value” shall be as specified in the plant-specific setpoint analysis. The expected as-found value reflects the expected normal drift of actual plant equipment, so that a degraded device can be identified before the Allowable Value limit is reached. The expected as-found value is also referred to as the Performance Test Acceptance Criteria (PTAC). The PTAC, recorded and maintained in a document established by the SCP, is applicable to automatic protection instrumentation functions for Reactor Trip, ESFAS actuation and permissive interlocks.

<u>ESFAS and SLS</u>

The ESFAS and SLS equipment are used for the decision logic processing of outputs from the RPS. The SLS is also used for manual control of ESF components for accident mitigation and to achieve safe shutdown. To meet the single failure criteria and accomodate on-line maintenance for four train ESF systems, four trains of ESFAS-SLS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the remaining trains will provide ESF actuation for the unit. Two train ESF systems are actuated by Trains A and D, or B and C of the ESFAS-SLS.

BACKGROUND (continued)

Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The ESFAS and SLS perform the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the MCR of the unit.

The digital output signals from all trains of the RPS are sensed by each ESFAS train and combined into logic that represent combinations indicative of various transients. If a required logic combination is completed, the ESFAS train will send actuation signals via the Safety Bus to its respective SLS train. The SLS actuates those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of these Bases. The SLS also actuates ESF components based on manual control signals received from non-safety Operational VDUs, and based on signals from Safety VDUs for the Manual Control of ESF Components Function.

The ESFAS and SLS have continuous automatic self-testing. When any one train is taken out of service for manual testing, the remaining trains are capable of providing unit monitoring and protection until the testing has been completed.

The automatic or manual actuation of ESF components is accomplished through solid state Actuation Outputs. The SLS energizes the Actuation Outputs appropriate for the condition of the unit. Each Actuation Output energizes one plant component. Actuation Outputs are tested in conjunction with their respective plant components. This test overlaps with the continuous automatic self-testing.

S-VDU and COM

The Safety VDUs (S-VDU) and Communication Subsystems (COM) provide backup controls for manual initiation of Reactor Trip and ESFAS Functions, and credited controls and indications for the Manual Control of ESF Components.

The S-VDU in each train consists of a VDU and S-VDU processor. There are two COM Subsystems in each train, COM-1 and COM-2.

BASES

BACKGROUND (continued)

The S-VDU provides backup controls for Manual Initiation of Reactor Trip (LCO 3.3.1) and ESFAS functions. Manual initiation signals are interfaced from the S-VDU to the RPS and ESFAS through COM-2, where they are combined with corresponding signals from non-safety Operational VDUs (O-VDU), through logic that prioritizes the S-VDU signal. The combined and prioritized S-VDU and O-VDU signals are then interfaced to the RPS or ESFAS where it is combined with the Manual Initiation pushbuttons, which are required by this LCO. These backup S-VDU controls are not credited in determining when the Manual Initiation Function is OPERABLE or in determining the number of required trains. However, these backup controls are considered in the Manual Initiation Function Completion Times for the Required Actions.

The S-VDU provides credited safety related displays and controls for the Manual Control of ESF Components Function. This Function supports the ESFAS and is used to achieve and maintain safe shutdown (e.g., LCO 3.5.2 for Safety Injection). Component control signals are interfaced from the S-VDU to the SLS through COM-2, where they are combined with corresponding signals from non-safety Operational VDUs (O-VDU), through logic that prioritizes the S-VDU signal. The combined and prioritized S-VDU and O-VDU signals are then interfaced to the SLS. Component position feedback signals for status displays are interfaced from the SLS to the S-VDU.

To meet the single failure criteria and accommodate on-line maintenance, for four train ESF systems, four trains of S-VDU and COM-2 are provided, each performing the same functions. If one train is taken out of service for maintenance or test purposes, the remaining trains will provide displays and manual controls for the unit. The S-VDU and COM-2 for Trains A and D, or Trains B and C support ESF systems with only two trains.

The S-VDU and COM-2 for each train are packaged in their own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The S-VDU and COM-2 have continuous automatic self-testing while in service. When any one train is taken out of service for manual testing, the remaining trains are capable of providing unit monitoring and protection until the testing has been completed.

COM-1 provides signal interfaces from the ESFAS and SLS to the PCMS for non-safety functions only, such as the display of ESF component position on non-safety Operational VDUs (O-VDU). Therefore, there are no operability requirements for COM-1.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each 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. For example, Low Pressurizer Pressure is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as Manual Initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function, listed in Table 3.3.2-1 in the accompanying LCO, to be OPERABLE. A channel is OPERABLE provided the "as-found" measured during surveillance testing, value does not exceed its associated Allowable Value, and provided the “as-left” value is within the specified calibration tolerance at the completion of each CHANNEL CALIBRATION. For analog measurements, Allowable Values are defined in terms pertinent to the five channel calibration settings 0%, 25%, 50%, 75% and 100%. For binary measurements there is one Allowable Value defined in terms pertinent to the state change at the Nominal Trip Setpoint. A Nominal Trip Setpoint is set more conservative than the Allowable Value to account for channel uncertainties. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of two or three channels in each instrumentation Function, two or three trains of Manual Initiation, and two or three trains in each logic Function. Three OPERABLE instrumentation channels in a two-out-of-three configuration are required when one ESFAS channel is also used as a control system input. When there are three or more OPERABLE channels, the SSA within the control system prevents the possibility of a shared channel failing in such a manner that it creates a transient that requires ESFAS action. The input failure is considered a single failure in the ESFAS and ESFAS remains capable of providing its protective function with the remaining two OPERABLE channels. The SSA ensures there is no potential for control system and protection system interaction that could simultaneously create a need for ESFAS initiation and disable one ESFAS channel. When there are less than three OPERABLE channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared channels, when there are only three required channels.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The two-out-of-three configuration allows one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two or three trains of logic and Manual Initiation functions are required to ensure no single random failure disables the ESFAS. The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents.

Due to redundant components within the PSMS, such as controllers, communication links and power supplies, an inoperable component may or may not result in an inoperable channel or train. Where an inoperable component results in an inoperable required channel or train, LCOs are entered. For inoperable components that do not result in inoperable channels or trains, LCOs are not entered.

ESFAS protection functions are as follows:

1. <u>ECCS Actuation</u>

   ECCS Actuation (ECCS) provides two primary functions:

   1. Primary side water addition to ensure maintenance or recovery of Reactor Vessel Water Level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F), and

   2. Boration to ensure recovery and maintenance of SDM (k_{eff}< 1.0).

   These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The ECCS signal is also used to initiate other Functions such as:

   - Phase A Isolation,
   - Containment Purge Isolation,
   - Reactor Trip,
   - Feedwater Isolation,
   - Start of Emergency Feedwater (EFW) pumps,
   - MCR Isolation, and
   - Reactor Coolant Pump Trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations,
- Trip of the reactor to limit power generation,
- Isolation of main feedwater (MFW) to limit secondary side mass losses,
- Start of EFW to ensure secondary side cooling capability,
- Isolation of the MCR to ensure habitability, and
- Trip of the Reactor Coolant Pump to prevent the unexpected Reactor Coolant Pump Trip after a small break LOCA.

a. <u>ECCS Actuation - Manual Initiation</u>

The LCO requires three trains to be OPERABLE. The operator can initiate ECCS at any time by using any two-out-of-four ECCS - Manual Initiation switches in the MCR. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each train consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates its own train directly. A signal from each pushbutton is also interfaced to all other trains via internal PSMS communication links. In addition to direct actuation by its own train pushbutton, each train is also actuated by two out of three Manual Initiation signals received from the other trains. The signals from the other trains are not credited in determining when the Manual Initiation Function is OPERABLE or in determining the number of required trains. However, these additional signals are considered in the Completion Times for the Required Actions.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. ECCS Actuation - Actuation Logic and Actuation Outputs

This LCO requires three trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the actuation output devices responsible for actuating the ESF equipment.

Manual and automatic initiation of ECCS must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a PA, but because of the large number of components actuated on an ECCS, actuation is simplified by the use of the manual actuation push buttons. Actuation Logic and Actuation Outputs must be OPERABLE in MODE 4 to support system level Manual Initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent over-pressurization of unit systems.

c. ECCS Actuation - High Containment Pressure

This signal provides protection against the following accidents:

- SLB inside containment,
- LOCA, and
- Feed line break inside containment.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

High Containment Pressure provides no input to any control functions. There are four High Containment Pressure channels in a two-out-of-four logic configuration. Three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

High Containment Pressure must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. <u>ECCS Actuation - Low Pressurizer Pressure</u>

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve,
- SLB,
- A spectrum of rod cluster control assembly ejection accidents (rod ejection),
- Inadvertent opening of a pressurizer relief or safety valve,
- LOCAs, and
- SG Tube Rupture.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

There are four Low Pressurizer Pressure channels in a two-out-of-four logic configuration. Pressurizer Pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, Reactor Trip, and ECCS. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more Low Pressurizer Pressure channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE Low Pressurizer Pressure channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared Low Pressurizer Pressure channels.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Nominal Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1 and 2, and in MODE 3 above the P-11 setpoint to mitigate the consequences of an HELB inside containment. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. Automatic ECCS Actuation below this pressure setpoint is then performed by the High Containment Pressure signal.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint, because the plant is in hot standby in preparation for a startup or shutdown process. Under hot standby conditions, reactor power is limited to decay heat so LOCA is not a critical condition in this situation. For SLB, the RCS boron concentration is higher (larger shutdown margin) and the moderator density coefficient is smaller due to the higher boron concentration compared to the FSAR Chapter 15 analysis. Thus, there is no need for automatic ECCS Actuation under these less limiting conditions. Therefore, when shutting down, the Low Pressurizer Pressure ECCS signal can be bypassed in MODE 3 below the P-11 setpoint. There is sufficient time margin for manual ECCS Actuation, if necessary. When starting up, the Low Pressurizer Pressure ECCS signal is automatically enabled above the P-11 setpoint.

Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. <u>ECCS Actuation - Low Main Steam Line Pressure</u>

Low Main Steam Line Pressure provides protection against the following accidents:

- SLB,
- Feed line break, and
- Inadvertent opening of an SG relief or an SG safety valve.

There are four Low Main Steam Line Pressure channels on each steam line in a two-out-of-four logic configuration. Main Steam Line Pressure provides control inputs to the Steam Generator Pressure Control System, and protection inputs to ECCS and Main Steam Line Isolation protective functions. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more Main Steam Line Pressure channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line. When there are less than three OPERABLE Main Steam Line Pressure channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared Main Steam Line Pressure channels.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

Low Main Steam Line Pressure must be OPERABLE in MODES 1 and 2, and MODE 3 above the P-11 setpoint. In these MODES, a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint because the plant is in hot standby in preparation for a startup or shutdown process. Under hot standby conditions, the RCS boron concentration is higher (larger shutdown margin) and the moderate density coefficient is smaller due to the higher boron concentration compared to the FSAR Chapter 15 analysis. Thus, there is no need for automatic ECCS Actuation under these less limiting conditions. Therefore, when shutting down, the Low Main Steam Line Pressure ECCS signal can be bypassed in MODE 3 below the P-11 setpoint. There is sufficient time margin for manual ECCS Actuation, if necessary. However, considering the potential impact to containment integrity due to pressure increase from a SLB, the High Main Steam Line Pressure Negative Rate signal is required to be OPERABLE in MODE 3 below the P-11 setpoint to provide automatic Main Steam Line Isolation. The High Main Steam Line Pressure Negative Rate signal is automatically enabled when the Low Main Steam

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Line Pressure ECCS signal is bypassed. When starting up, the Low Main Steam Line Pressure ECCS signal is automatically enabled above the P-11 setpoint, and the High Main Steam Line Pressure Negative Rate signal is automatically disabled.

This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. Containment Spray

Containment Spray provides two primary functions:

1. Lowers containment pressure and temperature after an HELB in containment, and

2. Reduces the amount of radioactive iodine in the containment atmosphere.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure,

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure, and

- Minimize corrosion of the components and systems inside containment following a LOCA.

The Containment Spray actuation signal starts the CS/RHR pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Containment spray is actuated manually or by High 3 Containment Pressure.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Containment Spray - Manual Initiation

The operator can initiate Containment Spray at any time from the MCR by simultaneously actuating two Containment Spray actuation switches per train for any two-out-of-four trains. Because an inadvertent actuation of Containment Spray could have such serious consequences, two switches must be actuated concurrently to initiate Containment Spray for each train. There are four sets of two switches each in the MCR. Concurrently actuating the two switches will actuate Containment Spray in each train in the same manner as the automatic actuation signal. Therefore, two Manual Initiation switches in a train are required to be OPERABLE for a train to be OPERABLE. Note that Manual Initiation of Containment Spray also actuates Phase B Containment Isolation.

Each train consists of two push buttons and the interconnecting wiring to the actuation logic cabinet. Each push button actuates its own train directly through two out of two logic. A signal from the output of this two out of two logic is also interfaced to all other trains via internal PSMS communication links. In addition to direct actuation by its own train pushbuttons, each train is also actuated by two out of three Manual Initiation signals received from the other trains. The signals from the other trains are not credited in the determining when the Manual Initiation Function is OPERABLE or in determining the number of required trains. However, these additional signals are considered in the Completion Times for the Required Actions.

For Containment Spray only two 50% trains are needed to achieve 100% capacity; therefore, only three of four trains of manual initiation are needed to meet the single failure criteria. However, for Phase B Containment Isolation, although only two trains are needed to meet the single failure criteria for any single containment penetration, the containment penetrations are distributed to all four trains. Therefore, since Containment Spray - Manual Initiation is a combined Function for Containment Spray and Phase B Containment Isolation, two switches in each of all four trains are required to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Spray - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Containment Spray must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a PA. However, because of the large number of components actuated on a Containment Spray, actuation is simplified by the use of the manual actuation push buttons. Actuation Logic and Actuation Outputs must be OPERABLE in MODE 4 to support system level Manual Initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray - High-3 Containment Pressure

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

High-3 Containment Pressure has four channels in a two-out-of-four logic configuration. Three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic.

High-3 Containment Pressure must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the High-3 Containment Pressure setpoint.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

For any single containment penetration, isolation can be accomplished by either of two redundant trains. However, all Containment Isolation functions are distributed among all four ESFAS trains.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A Isolation isolates all automatically isolable process lines, except component cooling water (CCW), at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A Containment Isolation is actuated automatically by ECCS Actuation, or manually via the Actuation Logic. All process lines penetrating containment, with the exception of CCW, are isolated.

CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and air or oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

Manual Phase A Containment Isolation is accomplished by two switches in the MCR. Each push button actuates its own train directly.

Note that manual actuation of Phase A Containment Isolation also actuates Containment Purge Isolation.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Phase B signal isolates CCW. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some system components do not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B Isolation would be into containment. Therefore, the combination of CCW System design and Phase B Isolation ensures the CCW System is not a potential path for radioactive release from containment.

Phase B Containment Isolation is actuated by the same signals that actuate Containment Spray including High-3 Containment Pressure, or Containment Spray - Manual Initiation, via the Actuation Logic. For containment pressure to reach a value high enough to actuate High-3 Containment Pressure, a large break LOCA or SLB must have occurred, and Containment Spray must have been actuated. RCP operation will no longer be required and CCW to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches per train for two-out-of-four trains are actuated concurrently, Phase B Containment Isolation and Containment Spray will be actuated in all trains.

a. <u>Containment Isolation - Phase A Isolation</u>

(1) <u>Phase A Isolation - Manual Initiation</u>

Manual Phase A Containment Isolation is actuated by two switches in the MCR. Each push button actuates its own train directly.

Note that Manual Initiation of Phase A Containment Isolation also actuates Containment Purge Isolation.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(2) Phase A Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Phase A Isolation valves are distributed to Trains A and D. Both trains must be OPERABLE.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is a potential for an accident to occur. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a PA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation push buttons. Actuation Logic and Actuation Outputs must be OPERABLE in MODE 4 to support system level Manual Initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation - ECCS Actuation

Phase A Containment Isolation is also initiated by all Functions that initiate ECCS Actuation. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their ECCS Actuation function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, ECCS Actuation, is referenced for all initiating Functions and requirements. Note that all four Containment Isolation trains are actuated when any two-out-of-four ECCS Actuation - Automatic or Manual Initiation signals are actuated.

b. Containment Isolation - Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Actuation Logic and Actuation Outputs, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(1) Phase B Isolation - Manual Initiation

Phase B Containment Isolation is manually initiated by Containment Spray – Manual Initiation. The Phase B Containment Isolation requirements for these Functions are the same as the requirements for their Containment Spray function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 2, Containment Spray, is referenced for all initiating Functions and requirements.

Note that all four Phase B Containment Isolation trains are actuated when any two-out-of-four Containment Spray – Manual Initiation signals are actuated.

(2) Phase B Isolation - Actuation Logic and Actuation Outputs

Manual and automatic initiation of Phase B Containment Isolation must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is a potential for an accident to occur. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a PA. However, because of the large number of components actuated on a Phase B Containment Isolation, actuation is simplified by the use of the manual actuation push buttons. Actuation Logic and Actuation Outputs must be OPERABLE in MODE 4 to support system level Manual Initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

Four trains of Phase B Containment Isolation - Actuation Logic and Actuation Outputs must be OPERABLE due to the distribution of Containment Isolation Valves to all four trains.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Main Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the main steam lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the main steam lines depressurize. Main Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven EFW pump during a feed line break.

Main Steam Line Isolation components are distributed to Trains A and D.

a. Main Steam Line Isolation - Manual Initiation

Manual Initiation of Main Steam Line Isolation can be accomplished from the MCR. There are two switches in the MCR, one for each train. Each MSIV is actuated from both trains. Therefore, either switch can initiate action to immediately close all MSIVs. The LCO requires two trains to be OPERABLE.

b. Main Steam Line Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Main Steam Line Isolation valves are distributed to Trains A and D. Both trains must be OPERABLE.

Manual Initiation and Actuation Logic and Actuation Outputs of Main Steam Line Isolation must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Main Steam Line Isolation - High-High Containment Pressure

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. High-High Containment Pressure provides no input to any control functions. There are four High-High Containment Pressure channels in a two-out-of-four logic configuration. Three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. The transmitters and electronics are located outside of containment. Therefore, they will not experience any adverse environmental conditions. The Nominal Trip Setpoint reflects only steady state instrument uncertainties.

High-High Containment Pressure must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the High-High Containment Pressure setpoint.

d. Main Steam Line Isolation - Main Steam Line Pressure

(1) Low Main Steam Line Pressure

Low Main Steam Line Pressure provides closure of the MSIVs in the event of an SLB to maintain at least two unfaulted SGs as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven EFW pump. Low Main Steam Line Pressure was discussed previously under ECCS Function 1.e.

Low Main Steam Line Pressure Function must be OPERABLE in MODES 1 and 2, and MODE 3 above the P-11 setpoint, in these MODES, a secondary side break, spuriously opened valve, or stuck open valve could result in the rapid

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

depressurization of the steam lines. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. In MODE 3 below the P-11 setpoint, an SLB inside containment will be terminated by automatic actuation via the High-High Containment Pressure signal. Stuck valve transients and SLBs outside containment will be terminated by the High Main Steam Line Pressure Negative Rate signal for Main Steam Line Isolation in MODE 3 below the P-11 setpoint when ECCS has been manually bypassed.

This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

(2) High Main Steam Line Pressure Negative Rate

High Main Steam Line Pressure Negative Rate provides closure of the all MSIVs for an SLB in MODE 3 below the P-11 setpoint, to maintain at least two unfaulted SGs as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually bypasses the Low Main Steam Line Pressure Main Steam Line Isolation signal in MODE 3 below the P-11 setpoint, the High Main Steam Line Pressure Negative Rate signal is automatically enabled. Main Steam Line Pressure provides both control and protection functions, as described previously under ECCS Function 1.e. There are four High Main Steam Line Pressure Negative Rate signals in a two-out-of-four logic configuration. Three OPERABLE channels are sufficient to satisfy requirements with a two-out-of-three logic on each steam line.

High Main Steam Line Pressure Negative Rate must be OPERABLE in MODE 3 below the P-11 setpoint. In this MODE, a secondary side break or stuck open valve could result in the rapid depressurization of the main steam line(s). Above the P-11 setpoint, this signal is automatically disable

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and the Low Main Steam Line Pressure signal is automatically enabled. The Main Steam Line Isolation Function is required to be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of significant enough quantities of energy to cause a cooldown of the RCS.

While the transmitters may experience elevated ambient temperatures due to an SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

This Function has a dynamic transfer function. The Time Constants for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

All Main Steam Isolation Functions are applicable in MODES 1, 2 and 3 as stated above, regardless of valve position, because the Functions are credited to mitigate spurious valve opening from Operational VDUs. In MODES 4, 5, and 6, these Functions are not required to be OPERABLE, as stated above.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Main Feedwater Isolation

The primary function of the Main Feedwater Isolation is to stop the excessive flow of feedwater into the SGs. This Function is necessary to mitigate the effects of a high water level in the SGs, which could result in excessive cooldown of the primary system. The High SG Water Level is due to excessive feedwater flows.

The Function on High-High SG Water Level is actuated when the level in any SG exceeds the high-high setpoint.

The Main Feedwater Isolation Function performs the following functions:

- Trips the MFW pumps,
- Shuts the MFW Isolation valves,
- Shuts the MFW Regulation Valves, the MFW Bypass Regulation Valves, and the SG Water Filling Control Valves.

This Function is actuated by High-High SG Water Level, an ECCS Actuation signal, or Manual Initiation.

The ECCS Actuation signal was discussed previously.

The Function on Low T_{avg} coincident with Reactor Trip closes all the Main Feedwater Regulation valves.

Main Feedwater Isolation Valves, MFW Regulation Valves, MFW Bypass Regulation Valves, and SG Water Filling Control Valves are distributed to Trains A and D.

a. Main Feedwater Isolation - Manual Initiation

Manual Initiation of Main Feedwater Isolation can be accomplished from the MCR. There are two switches in the MCR, one for each train. Each of the valves is actuated from both trains. Therefore, either switch can initiate action to immediately actuate all Main Feedwater Isolation Components. The LCO requires two trains to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Main Feedwater Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. All Main Feedwater Isolation Components are distributed to Trains A and D. Both trains must be OPERABLE.

c. Main Feedwater Isolation - High High Steam Generator Water Level

This signal provides protection against excessive feedwater flow. There are four High High Steam Generator Water Level channels in a two-out-of-four logic configuration for each Steam Generator. The ESFAS SG Water Level instruments provide input to the SG Water Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When there are three or more OPERABLE High-High Steam Generator Water Level channels for each Steam Generator, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE High-High Steam Generator Water Level channels for each Steam Generator, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for High-High Steam Generator Water Level channels, since there are only three required channels for each Steam Generator.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Main Feedwater Isolation - ECCS Actuation

Main Feedwater Isolation is also initiated by all Functions that initiate ECCS Actuation. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their ECCS Actuation function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, ECCS Actuation, is referenced for all initiating functions and requirements. Note that both Main Feedwater Isolation trains are actuated when any two-out-of-four ECCS Actuation - Automatic or Manual Initiation signals are actuated.

e. Main Feedwater Isolation - Low T_{avg}

This Function is actuated when T_{avg} is less than the low setpoint coincident with Reactor Trip. It closes only the Main Feedwater Regulation valves.

There are four Low T_{avg} channels (one per loop) in a two-out-of-four configuration. Three channels of T_{avg} are required to be OPERABLE. The T_{avg} channels are combined in a logic such that two out of three channels cause a trip for the Function. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of three OPERABLE channels in a two-out-of-four configuration ensures no single random failure disables the Low T_{avg} Function.

T_{avg} channels provide inputs to both control and protection functions. T_{avg} channels provide control inputs to the Rod Control System, Pressurizer Water Level Control System, and Turbine Bypass Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more T_{avg} channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE T_{avg} channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared T_{avg} channels.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

With the T_{avg} resistance temperature detectors (RTDs) located inside the containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Nominal Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

The Main Feedwater Isolation - Low T_{avg} signal is enabled by the Main Feedwater Isolation - Reactor Trip, P-4 interlock, described below.

Coincident with Reactor Trip, P-4

The Main Feedwater Isolation - Low T_{avg} signal is enabled when the reactor is tripped as indicated by the P-4 interlock. Therefore, the requirements for the P-4 interlock are not repeated in Table 3.3.2-1. Instead, Function 11.a, Reactor Trip, P-4, is referenced for the initiating Function and requirements. Note that both Turbine Trip actuation trains, Trains A and D, are actuated when any two-out-of-four RTB trains are actuated.

All Main Feedwater Isolation Functions, except for the sub-function of High-High Steam Generator Water Level, which trips the MFW pumps and closes the MFIVs, and SGWFCVs, must be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5, and 6, the MFW System is not in service and the Isolation Functions are not required to be OPERABLE.

The sub-function of the MFW Isolation on High-High Steam Generator Water Level, which trips the MFW pumps and closes the MFIVs and SGWFCVs, must be OPERABLE in MODES 1 and 2, and in MODE 3 above the P-11setpoint.

The sub-function may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. This manual bypass is needed to allow control of steam generator water level using the SGWFCVs under these conditions. The MFIVs and SGWFCVs are configured in series such that the feedwater flow rate is limited by the SGWFCV capacity which is a very small fraction of the nominal feedwater flow. The manual bypass is acceptable because expected feedwater flow due to open SGWFCVs is not a critical concern under these

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

conditions. Sufficient time margin exists for manual SGWFCV closure, if necessary. Therefore, manual bypass of the automatic trip of MFW pumps and automatic closure of MFIVs and SGWFCVs on High-High SG Water Level in MODE 3 below the P-11 setpoint is acceptable and necessary to maintain the Steam Generators filled with water in preparation for shutdown conditions (wet layup operation). When starting up, the automatic trip of MFW pumps and automatic closure of MFIVs and SGWFCVs on High-High SG Water Level is automatically enabled above the P-11 setpoint.

These Functions are applicable in MODES 1, 2 and 3 as stated above, regardless of valve position, because the Functions are credited to mitigate spurious valve opening from Operational VDUs. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Emergency Feedwater Actuation

The EFW Actuation System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has four trains, with two motor driven pumps and two turbine driven pumps, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The LCO requires three OPERABLE EFW trains. The normal source of water for the EFW System is the Emergency Feedwater pit (EFW pit). This pit has a sufficient capacity to lead the plant safe shutdown. If the water level of EFW pit reached low-low level, operators are given alarm in MCR. Then the EFW pumps will be stopped or the water source will be switched to Demineralized Water Storage Tank manually to keep the sufficient EFW if necessary.

a. Emergency Feedwater Actuation - Manual Initiation

Manual Initiation of Emergency Feedwater Actuation can be accomplished from the MCR. There are four switches in the MCR, one for each train. Each switch actuates its own train directly. A signal from each switch is also interfaced to all other trains via internal PSMS communication links. In addition to direct actuation by its own train switch, each train is also actuated by two out of three Manual Initiation signals received from the other trains. The signals from the other trains are not credited in determining when the Manual Initiation Functions is OPERABLE or in determining the number of required trains. However, these additional signals are considered in the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Completion Times for the Required Actions. The LCO requires three trains to be OPERABLE

b. Emergency Feedwater Actuation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Three trains must be OPERABLE.

c. Emergency Feedwater Actuation - Low Steam Generator Water Level

Low SG Water Level provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. There are four Low SG Water Level channels in a two-out-of-four logic configuration. Low SG Water Level provides input to the SG Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more Low SG Water Level channels are OPERABLE for each Steam Generator, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE Low SG Water Level channels for each Steam Generator, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for Low SG Water Level channels, since there are only three required channels for each Steam Generator.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Nominal Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Emergency Feedwater Actuation - ECCS Actuation

An ECCS Actuation signals all four EFW trains. The EFW initiation functions are the same as the requirements for their ECCS Actuation function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, ECCS Actuation, is referenced for all initiating functions and requirements.

e. Emergency Feedwater Actuation - Loss of Offsite Power

A loss of offsite power will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal. The loss of offsite power is detected by a voltage drop on each Class 1E bus (4 trains). The voltage drop is detected by three undervoltage devices on each bus, in a two out of three configuration. Loss of Power to a Class 1E bus will actuate its respective EFW train (with either its motor or turbine driven pump). This ensures that, for a sitewide loss of offsite power, at least two SGs contain enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the Reactor Trip.

The LCO requires three OPERABLE undervoltage devices on each Class 1E bus corresponding to each OPERABLE EFW train.

This Function has Time Delays. The Time Delays for this Function are recorded and maintained in a document established by the Setpoint Control Program (SCP).

Functions 6.a through 6.e must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. Low SG Water Level in any operating SG will cause the EFW trains to actuate. The system is aligned so that upon a start of the EFW pump, water immediately begins to flow to the SGs. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, EFW actuation does not need to be OPERABLE because either EFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

f. Emergency Feedwater Actuation - Trip of All Main Feedwater Pumps

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each motor driven MFW pump is equipped with redundant breaker position sensing devices. An open supply breaker indicates that the pump is not running. Emergency Feedwater Actuation on Trip of All Main Feedwater Pumps is an anticipatory function that is not credited in the safety analysis. Therefore, this function does not need to meet the single failure criterion; the LCO requires one OPERABLE channel per pump (i.e., one of the redundant breaker position sensing devices on each pump). A trip of all MFW pumps actuates all EFW trains to ensure that at least two SGs are available with water to act as the heat sink for the reactor.

This function must be OPERABLE in MODES 1 and 2. This ensures that at least two SGs are provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus MFW pump trip is not indicative of a condition requiring automatic EFW initiation.

7. Emergency Feedwater Isolation

One of the objectives of EFW Isolation is to prevent SG overfill in the event of SGTR. The Other objective of EFW Isolation is to stop the flow of EFW into the affected SG in the event of MSLB. For both objectives, the EFW Isolation Functions are automatically actuated by High SG Water Level signal, or by Low Main Steam Line Pressure signal. The Function may also be actuated manually. The EFW Isolation Function is actuated separately for each SG, either manually or automatically. EFW Isolation valves are distributed to all four trains, with two trains of valves for each SG.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Emergency Feedwater Isolation - Manual Initiation

This LCO requires 2 EFW Isolation - Manual Initiation trains for each SG. Each Manual Initiation train closes the EFW isolation valve for one train on one SG. Two Manual Initiation trains must be OPERABLE for each SG to ensure each SG can be isolated with a single failure.

b. Emergency Feedwater Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Each Actuation Logic and Actuation Outputs train closes the EFW isolation valve for one train on one SG. Two Actuation Logic and Actuation Outputs trains for each SG must be OPERABLE to ensure each SG can be isolation with a single failure.

Manual and automatic initiation of EFW Isolation Functions must be OPERABLE in MODES 1, 2 and 3. In these MODES, the SGs are in operation. In MODES 4, 5, and 6, SGs are not in service and this Function is not required to be OPERABLE.

c. Emergency Feedwater Isolation - High Steam Generator Water Level Coincident with P-4 signal and No Low Main Steam Line Pressure

This signal provides protection against damaged SG overfill. There are four High Steam Generator Water Level channels in a two-out-of-four logic configuration for each Steam Generator. The ESFAS SG Water Level instruments provide input to the SG Water Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more High SG Water Level channels are OPERABLE for each Steam Generator, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE High SG Water Level channels for each Steam Generator, the SSA cannot prevent erroneous control system operation due to an

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

input failure. This is reflected in the LCO Completion Times for High SG Water Level channels, since there are only three required channels for each Steam Generator.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

High Steam Generator Water Level must be OPERABLE in MODES 1 and 2, and MODE 3 above the P-11 setpoint. In these MODES, the SGs are in operation. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. This function is not required to be OPERABLE in MODE 3 below the P-11 setpoint, because the plant may be transitioning from using the SGs as a heat sink to using the RHR system. This function is bypassed in MODE 3 below the P-11 setpoint to allow the operator to control EFW during the transition to RHR cooling and to maintain the Steam Generators filled with water in preparation for shutdown conditions (wet layup operation). When starting up, the High Steam Generator Water Level signal is automatically enabled above the P-11 setpoint.

In MODES 4, 5, and 6, SGs are not in service and this Function is not required to be OPERABLE.

d. Emergency Feedwater Isolation - Low Main Steam Line Pressure

This signal provides protection against excessive cooling from damaged SG. A steam line break or a feed line break inside of containment would result in a low steam line pressure.

Main Steam Line Pressure provides both control and protection functions, as described previously under ECCS Function 1.e. There are four Low Main Steam Line Pressure channels on each steam line in a two-out-of-four logic configuration. Three OPERABLE channels on each main steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Low Main Steam Line Pressure must be OPERABLE in MODES 1 and 2, and MODE 3 above the P-11 setpoint. In these MODES, the SGs are in operation. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. This function is not required to be OPERABLE in MODE 3 below the P-11 setpoint, because a secondary break is not limiting under these conditions, as described previously. There is sufficient time margin for manual Emergency Feedwater Isolation, if necessary. When starting up, the Low Main Steam Line Pressure signal is automatically enabled above the P-11 setpoint.

In MODES 4, 5, and 6, SGs are not in service and this Function is not required to be OPERABLE.

8. <u>CVCS Isolation</u>

The objective of CVCS Isolation is to prevent Pressurizer overfill in the event of a CVCS malfunction. For this objective, the CVCS Isolation is automatically actuated by High Pressurizer Water Level signal. The Function may also be actuated manually.

CVCS Isolation valves are distributed to Trains A and D. Both trains must be OPERABLE.

a. <u>CVCS Isolation – Manual Initiation</u>

Manual Initiation of CVCS Isolation can be accomplished from the MCR. There are two switches in the MCR, one for each train. Each CVCS Isolation Valve is actuated from both trains. Therefore, either switch can initiate action to immediately close all CVCS Isolation Valves. This LCO requires 2 Manual CVCS Isolation Actuation switches.

b. <u>CVCS Isolation – Actuation Logic and Actuation Outputs</u>

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. CVCS Isolation valves are distributed to Trains A and D. Both trains must be OPERABLE.

Manual and automatic initiation of CVCS Isolation Functions must be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5, and 6, the Pressurizer may be filled with water and this Function is not required to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. CVCS Isolation - High Pressurizer Water Level

This signal provides protection against that the Pressurizer overfill in the event of CVCS malfunction.

There are four High Pressurizer Water Level channels in a two-out-of-four logic configuration. Pressurizer Water Level provides input to the Pressurizer Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more High Pressurizer Water Level channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE High Pressurizer Water Level channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for High Pressurizer Water Level channels, since there are only three required channels.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Nominal Trip Setpoint reflects only steady state instrument uncertainties.

High Pressurizer Water Level must be OPERABLE in MODES 1 and 2, and MODE 3 above the P-11 setpoint. This signal may be manually bypassed by the operator in MODE 3 below the P-11 setpoint. This function is not required to be OPERABLE in MODE 3 below the P-11 setpoint, because the Pressurizer Water Level is much lower than in higher MODES providing a larger time margin to the pressurizer becoming full. Therefore, the automatic CVCS Isolation on High Pressurizer Water Level function is not required under these conditions. When starting up, the High Pressurizer Water Level signal is automatically enabled above the P-11 setpoint.

In MODES 4, 5, and 6, the Pressurizer may be filled with water and this Function is not required to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Turbine Trip

The primary functions of the Turbine Trip are to prevent damage to the turbine due to water in the steam lines, and to stop the excessive cooldown of the primary system.

The Turbine Trip Function is actuated by High-High Steam Generator Water Level or on Reactor Trip, P-4.

a. Turbine Trip - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Four Turbine Trip solenoid valves are arranged in a two-out-of-two configuration, taken separately for Train A and Train D. A Turbine Trip will be generated by Train A or Train D. Therefore a single train failure will not prevent a valid Turbine Trip. The LCO requires two trains, Trains A and D, to be OPERABLE.

b. Turbine Trip - Reactor Trip, P-4

The turbine is tripped on a Reactor Trip. Turbine trip on Reactor Trip is an un-credited non-safety function in the safety analysis. However, Turbine Trip on Reactor Trip is assumed in the safety analysis in order to prevent unnecessary ECCS Actuation and to shift to the safe shutdown state by appropriate actions after AOO and PA conditions.

Turbine Trip is initiated when the reactor trips as indicated by the P-4 interlock. Therefore, the requirements for the P-4 interlock are not repeated in Table 3.3.2-1. Instead, Function 11, Reactor Trip P-4, is referenced for the initiating Function and requirements. Note that both Turbine Trip actuation trains, Trains A and D, are actuated when any two-out-of-four RTB trains are actuated.

c. High-High Steam Generator Water Level

The High-High Steam Generator Water Level signal prevents water in the steam lines that could lead to turbine generator damage. Turbine trip on High-High Steam Generator Water Level is an un-credited non-safety function in the safety analysis.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

There are four High-High Steam Generator Water Level channels in a two-out-of-four logic configuration for each Steam Generator. Note that both Turbine Trip actuation trains, Tains A and D, are actuated when any two-out-of-four High-High Steam Generator Water Level channels are actuated.

The PSMS SG Water Level instruments provide input to the SG Water Level Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA). When three or more High-High SG Water Level channels are OPERABLE for each Steam Generator, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE High-High SG Water Level channels for each Steam Generator, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for High-High SG Water Level channels, since there are only three required channels for each Steam Generator.

10. <u>Reactor Coolant Pump Trip</u>

TMI Action Plan Item II.K.3.5 (Ref. 1) requires automatic trip of reactor coolant pumps (RCPs) following a loss-of-coolant accident (LOCA). The requirement is based on the consideration that a delayed-trip or continuous operation of the RCPs during a small break LOCA would lead to more severe consequences than if the RCPs are tripped early following a postulated break. Tripping all the RCPs early during a small break LOCA precludes the occurrence of excessive fuel cladding temperature.

a. <u>Reactor Coolant Pump Trip – ECCS Actuation coincident with P-4 signal</u>

The consequence of continuous RCP operation is the extensive liquid discharge from the break beyond the time that the system would drained down to allow steam discharge from the break had the pumps been immediately tripped. Therefore pump trip following a Reactor Trip and indication of ECCS Actuation would be effective.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

For the small break LOCA analysis, the loss of offsite power triggered by Reactor Trip signal is conservatively assumed, which would cause the earliest RCP trip. In case that the automatic RCP trip is enabled, an earlier RCP trip results in earlier flow coastdown leading to more severe consequences.

11. Engineered Safety Features Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to bypass some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

a. Engineered Safety Features Actuation System Interlocks - Reactor Trip, P-4

The P-4 Interlock is enabled when RTBs have opened in two-out-of-four RTB trains. RTB position signals from each RTB are interfaced to all PSMS trains via internal PSMS data links so that the P-4 interlock is generated independently within each train. Therefore this LCO requires three trains to be OPERABLE.

This Function allows operators to take manual control of ECCS systems after the initial phase of ECCS Actuation is complete. Once ECCS is overridden, automatic actuation of ECCS cannot occur again until the RTBs have been manually closed. The functions of the P-4 interlock are:

- Trip the main turbine,
- Close MFW Regulation Valves coincident with Low T_{avg},
- Enable a manual override of ECCS Actuation and prevent ECCS reactuation,
- EFW Isolation coincident with High SG Water Level and No Low Main Steam Line Pressure, and
- Trip the Reactor Coolant Pump coincident with ECCS Actuation.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Each of the above Functions except Reactor Coolant Pump Trip is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a Reactor Trip. An excessive cooldown of the RCS following a Reactor Trip could cause an insertion of positive reactivity with a subsequent increase in generated power. Reactor Coolant Pump Trip function is interlocked with P-4 to prevent the unexpected Reactor Coolant Pump Trip after a small break LOCA. The unexpected Reactor Coolant Pump Trip after a small break LOCA could cause the increasing of the Peak Clad Temperature (PCT). To avoid such these situations, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint.

This Function must be OPERABLE in MODES 1, 2, and 3. In these MODES, the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, the MFW System, and the Turbine Bypass System are not in operation.

b. <u>Engineered Safety Features Actuation System Interlocks - Pressurizer Pressure, P-11</u>

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of ECCS, Main Steam Line Isolation, CVCS Isolation, EFW Isolation or Main Feedwater Isolation on High-High SG Water Level.

With two-out-of-four Pressurizer Pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually bypass the Low Pressurizer Pressure and Low Main Steam Line Pressure ECCS Actuation signals, the Low Main Steam Line Pressure Main Steam Line Isolation signal, the CVCS Isolation signal, the EFW Isolation signals, and the High-High SG Water Level Main Feedwater Isolation signal (previously discussed). When the Low Main Steam Line Pressure Main Steam Line Isolation signal is manually bypassed, a Main Steam Line Isolation signal on High Main Steam Line Pressure Negative Rate is enabled. This provides protection for an SLB by closure of the MSIVs.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

With two-out-of-three Pressurizer Pressure channels above the P-11 setpoint, the Low Pressurizer Pressure and Low Main Steam Line Pressure ECCS Actuation signals, the Low Main Steam Line Pressure Main Steam Line Isolation signal, the CVCS Isolation signal, the EFW Isolation signals, and the High-High SG Water Level Main Feedwater Isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset buttons. When the Low Main Steam Line Pressure Main Steam Line Isolation signal is enabled, the Main Steam Isolation on High Main Steam Line Pressure Negative Rate is disabled.

The Nominal Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of ECCS, Main Steam Line Isolation, CVCS Isolation, EFW Isolation or Main Feedwater Isolation on High-High SG Water Level. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

12. Containment Purge Isolation

Containment Purge Isolation initiates on Containment High Range Area Radiation, an ECCS Actuation signal, by Manual Initiation of Containment Isolation Phase A, or by Manual Initiation of Containment Spray.

Containment Purge Isolation components are distributed to PSMS Trains A and D. Two trains are sufficient to provide the safety function. Both are required to be OPERABLE to provide the safety function with a concurrent single failure.

a. Containment Isolation Phase A - Manual Initiation

Containment Purge Isolation is manually initiated by Containment Isolation Phase A - Manual Initiation. The Containment Purge Isolation requirements for this Function are the same as the requirements for the Containment Isolation Phase A Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 3.a, Containment Isolation Phase A- Manual Initiation, is referenced for all initiating Functions and requirements.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Spray - Manual Initiation

Containment Purge Isolation is manually initiated by Containment Spray - Manual Initiation. The Containment Purge Isolation requirements for this Function are the same as the requirements for the Containment Spray Function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 2.a, Containment Spray – Manual Initiation, is referenced for all initiating Functions and requirements.

Note that both Containment Purge Isolation trains are actuated when any two-out-of-four Containment Spray - Manual Initiation signals are actuated.

c. Containment Purge Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Containment Purge Isolation valves are distributed to Trains A and D. Both trains must be OPERABLE.

d. Containment Purge Isolation - ECCS Actuation

Containment Purge Isolation is also initiated by all Functions that initiate ECCS. The Containment Purge Isolation requirements for these Functions are the same as the requirements for the ECCS function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, ECCS, is referenced for all initiating Functions and requirements.

Note that both Containment Purge Isolation trains are actuated when any two-out-of-four ECCS - Automatic or Manual Initiation signals are actuated.

e. Containment Purge Isolation - Containment High Range Area Radiation

Containment High Range Area Radiation has four channels in a two-out-of-four logic configuration. Three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Containment Purge Isolation Functions are required OPERABLE in MODES 1, 2, 3, and 4. Under these conditions, the potential exists for an accident that could release significant fission product radioactivity into containment. Therefore, the Containment Purge Isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 including fuel handling in progress, the Containment Purge Isolation instrumentation is not required to be OPERABLE. This is because the doses at the exclusion area boundary, at the low population zone outer boundary, and in the MCR are maintained within acceptable limits for the case where a fuel handling accident occurs without the containment being isolated, as described in FSAR Section 15.7.4 (Ref. 10).

13. <u>Main Control Room Isolation</u>

The MCR Isolation function provides an enclosed MCR environment from which the unit can be operated following an uncontrolled release of radioactivity. MCR Isolation controls the Main Control Room HVAC System (MCRVS) which includes two subsystems: Main Control Room Emergency Filtration System (MCREFS) and Main Control Room Air Temperature Control System (MCRATCS), described in the FSAR Chapter 16 Section 3.7.10.

There are four MCR Isolation trains. Trains A and D of MCR Isolation control two 100% capacity trains of subsystem MCREFS, and all four trains of MCR Isolation control four 50% capacity trains of subsystem MCRATCS. Two trains of MCR Isolation, including A or D, must actuate to properly provide the safety function (i.e., isolate and supply filtered air to the MCR), and three trains, including A and D, must be OPERABLE to provide the safety function with a concurrent single failure.

The MCR Isolation actuation instrumentation consists of redundant radiation monitors. A high radiation signal will initiate all four MCR Isolation trains. The MCR operator can also initiate MCR Isolation trains by manual switches in the MCR. MCR Isolation is also actuated by an ECCS Actuation signal.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The MCR must be kept habitable for the operators stationed there during accident recovery and post accident operations. The MCR Isolation function acts to terminate the supply of unfiltered outside air to the MCR, initiate filtration, and allows pressurization of the MCR. These actions are necessary to ensure the MCR is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of the MCR personnel.

In MODES 1, 2, 3, and 4, the radiation monitor actuation of MCR Isolation is a backup for the ECCS Actuation. This ensures initiation of the MCR Isolation during a loss of coolant accident or steam generator tube rupture.

The radiation monitor actuation of MCR Isolation during movement of irradiated fuel assemblies are the primary means to ensure MCR habitability in the event of a fuel handling accident.

The MCREFS and MCRATCS components (e.g., fans, dampers) can be manually controlled by the Safety VDUs (S-VDUs) of the corresponding train, and by the non-safety operational VDUs (O-VDUs). MCR Isolation signals, (either automatically or manually initiated) have priority over all manual component control signals, and therefore will block any signals from the O-VDUs, including spurious signals.

The automatic initiation of MCR Isolation is credited to ensure any spurious signals from the non-safety O-VDUs cannot prevent the MCR Isolation safety function. To accommodate various inoperable conditions, MCREFS and/or MCRATCS components are manually placed in the position they would be automatically actuated to by the MCR Isolation signal. For conditions where the automatic initiation function is inoperable, the MCRVS O-VDU Disconnect function is manually activated from the S-VDU for the affected MCREFS and/or MCRATCS train(s). The MCRVS O-VDU Disconnect function blocks signals from the O-VDUs, including spurious signals, in the same manner as the credited automatic initiation signal.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Main Control Room Isolation - Manual Initiation

The operator can initiate MCR Isolation for all four MCR Isolation trains at any time by using four Manual Initiation switches in the MCR. Each push button actuates its own train directly. A signal from each pushbutton is also interfaced to all other trains via internal PSMS communication links. In addition to direct actuation by its own train pushbutton, each train is also actuated by two-out-of-three Manual Initiation signals received from the other trains. The signals from the other trains are not credited in determining when the Manual Initation Function is OPERABLE or in determining the number of required trains. However, these additional signals are considered in the Completion Times for the Required Actions. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO requires three trains, including A and D, to be OPERABLE due to the two train configuration of MCREFS and four train configuration of MCRATCS, as described above.

Each train consists of one push button and the interconnecting wiring to the ESFAS cabinet.

b. Main Control Room Isolation - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b., ECCS Actuation. However, for MCR Isolation three trains, including A and D, must be OPERABLE due to the two main configuration of MCREFS and four train configuration of MCRATCS, as described above.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Main Control Room Isolation - Main Control Room Radiation

There are three kinds of Main Control Room Radiation monitor functions (gas monitor, iodine monitor, and particulate monitor). Each monitoring function includes two detectors of Train A and D. RPS trains A and D provide separate digital bistable setpoint comparison functions for each monitor. These digital bistable output signals are distributed from RPS trains A and D to each of the four ESFAS trains. Within each of the four ESFAS trains the MCR Isolation signal is actuated on a signal from either the A or D train detectors using 1-out-of-2 logic for each type of monitor.

The LCO specifies two required Main Control Room Radiation monitors for each function to ensure that the radiation monitoring instrumentation necessary to initiate the MCR Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

d. Main Control Room Isolation - ECCS ACTUATION

MCR Isolation is also initiated by all Functions that initiate ECCS Actuation. The MCR Isolation requirements for these Functions are the same as the requirements for their ECCS Actuation function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, ECCS Actuation, is referenced for all initiating Functions and requirements. Note that all four MCR Isolation trains are actuated when any two-out-of-four ECCS Actuation - Automatic or Manual Initiation signals are actuated.

The MCR Isolation Functions must be OPERABLE in MODES 1, 2, 3, and 4, and during movement of irradiated fuel assemblies.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Block Turbine Bypass and Cooldown Valves

The Block Turbine Bypass and Cooldown Valves function prevents the overcooling of the reactor coolant system when T_{avg} is decreased abnormally.

Block turbine bypass and cooldown valves are distributed to Trains A and D.

a. Block Turbine Bypass and Cooldown Valves – Manual Initiation

Manual Initiation of Block Turbine Bypass and Cooldown Valves can be accomplished from the MCR. There are two switches in the MCR, one for each train. Each Turbine Bypass and Cooldown Valve is blocked from both trains. Therefore, either switch can be initiated to immediately block the opening of all Turbine Bypass and Cooldown Valves. This LCO requires 2 Manual Block Turbine Bypass and Cooldown Valves Actuation switches to be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5 and 6, the average coolant temperature is below the Low-Low T_{avg} Signal setpoint and this Function is not required to be OPERABLE .

b. Block Turbine Bypass and Cooldown Valves - Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Block Turbine Bypass and Cooldown Valves are distributed to Trains A and D. Both trains must be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5 and 6, the average coolant temperature is below the Low-Low T_{avg} Signal setpoint and this Function is not required to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Block Turbine Bypass and Cooldown Valves - Low-Low T_{avg} Signal

There are four Low T_{avg} channels (one per loop) in a two-out-of-four configuration. Three channels of T_{avg} are required to be OPERABLE. The T_{avg} channels are combined in a logic such that two out of three channels cause a trip for the Function. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of three OPERABLE channels in a two-out-of-four configuration ensures no single random failure disables the Low T_{avg} Function.

T_{avg} channels provide inputs to both control and protection functions. T_{avg} channels provide control inputs to the Rod Control System, Pressurizer Water Level Control System, and Turbine Bypass Control System. The interface from the safety channels in the PSMS to the PCMS is through the Signal Selection Algorithm (SSA).

When three or more T_{avg} channels are OPERABLE, the SSA ensures an input failure to the control system does not result in erroneous control system action that would require the protection function actuation. Therefore, the protection function requires only two additional channels to provide the protection function actuation (i.e., three channels total). Three channels total must be OPERABLE. When there are less than three OPERABLE T_{avg} channels, the SSA cannot prevent erroneous control system operation due to an input failure. This is reflected in the LCO Completion Times for shared T_{avg} channels.

With the T_{avg} resistance temperature detectors (RTDs) located inside the containment, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Nominal Trip Setpoint reflects both steady state and adverse environmental instrumental uncertainties.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Low-Low T_{avg} for Cooldown Turbine Bypass Valves must be OPERABLE in MODES 1 and 2, and MODE 3 above the setpoint of Low-Low T_{avg}. This signal for Cooldown Turbine Bypass Valves may be manually overridden by the operator when shutting down. This Function for Cooldown Turbine Bypass Valves is not required to be OPERABLE in MODE 3 below the setpoint of Low-Low T_{avg}, because there is insufficient energy in the SGs and a larger time margin is allowed to block Cooldown Turbine Bypass Valves. When starting up, Low-Low T_{avg} for Cooldown Turbine Bypass Valves is automatically enabled above the setpoint of Low-Low T_{avg} Signal.

Low-Low T_{avg} for Turbine Bypass Valves (except Cooldown Turbine Bypass Valves) must be OPERABLE in MODES 1, 2, and 3.

In MODES 4, 5 and 6, the average coolant temperature is below the Low-Low T_{avg} Signal setpoint and this Function is not required to be OPERABLE.

15. <u>Manual Control of ESF Components</u>

The Manual Control of ESF Components Function provides credited manual controls for accidents and safe shutdown, as defined for the plant components in LCO 3.4 through 3.7.

a. <u>Manual Control of ESF Components - S-VDU</u>

An S-VDU train consists of a VDU and S-VDU processor. An S-VDU train must be OPERABLE for the same trains and MODES as required for the controlled ESF components. For ESF components with four trains (three required trains), three S-VDU trains must be OPERABLE for the same three trains as the required OPERABLE ESF components. For ESF components with only two required trains, an S-VDU train must be OPERABLE for the same two trains as the required OPERABLE ESF components. However, for Phase B Containment Isolation, there are two-train components assigned to Trains A and D, and two-train components assigned to Trains B and C. Therefore, because all four trains are required for Phase B Containment Isolation, all four trains of S-VDU are required. Since Manual

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Control of ESF Components is required for some ESF systems in all MODES, S-VDU must be OPERABLE to support ESF components in MODES 1, 2, 3, 4, 5 and 6.

b. Manual Control of ESF Components - COM-2

COM-2 combines the manual control signals from non-safety Operational VDUs with the manual control signals from S-VDUs. The combined signal is interfaced to the Actuation Logic in the SLS for manual control of ESF components. Since COM-2 controls ESF components assigned to all four trains as explained above for the S-VDU, some of which are required in all MODES, four COM-2 trains are required in MODES 1, 2, 3, 4, 5 and 6.

c. Manual Control of ESF Components - Actuation Logic and Actuation Outputs

The Actuation Logic and Actuation Outputs for the Manual Control of ESF Components Function is implemented in the SLS. For ESFAS components, the SLS combines the automatic actuation signals from the ESFAS with the manual control signals from COM-2. For all ESF components the SLS generates Actuation Outputs, based on automatic and/or manual control signals, which control the state of the ESF components. For the Manual Control of ESF Components Function, the Actuation Logic and Actuation Outputs within any SLS controller must be OPERABLE in the same MODES and for the same trains as for the required ESF components. LCO 3.4 through 3.7 provide MODE and train requirements applicable to ESF components.

16. Main Steam Relief Line Isolation

The Main Steam Relief Line Isolation is to prevent the overcooling of the reactor coolant system in the event of MSRV malfunction. For this objective, the Main Steam Relief Line Isolation is automatically actuated by the Low Main Steam Line Pressure signal. The Function may also be actuated manually. The Main Steam Relief Line Isolation function is actuated separately for each steam relief line, either manually or automatically.

The control of the MSRV and the MSRVBV are distributed to two different trains.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Main Steam Relief Line Isolation – Manual Initiation

Manual initiation of Main Steam Relief Line Isolation can be accomplished from the MCR. There are two switches for each steam relief line in the MCR, one for each train. Each Manual Initiation train closes either the MSRV or the MSRVBV. Two Manual Initiation trains must be OPERABLE for each steam line to ensure each steam relief line can be isolated even with a single failure.

Manual Initiation of this Function must be OPERABLE in MODES 1, 2, and 3. In MODES 4, 5, and 6, the SGs are not in service and this Function is not required to be OPERABLE.

b. Main Steam Relief Line Isolation – Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Each Actuation Logic and Actuation Outputs train closes either the MSRV or the MSRVBV on one steam relief line. Two Actuation Logic and Actuation Outputs for each steam relief line must be OPERABLE to ensure each steam relief line can be isolated even with a single failure.

Actuation Logic and Actuation Outputs of this Function must be OPERABLE in MODES 1, 2, and 3. In MODES 4, 5, and 6, the SGs are not in service and this Function is not required to be OPERABLE.

c. Main Steam Relief Line Isolation – Low Main Steam Line Pressure

This signal provides protection against overcooling from the affected steam relief line. The inadvertent opening of an MSRV would result in a low steam line pressure.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Main Steam Line Pressure provides both control and protection functions, as described previously under ECCS Function 1.e. There are four Low Main Steam Line Pressure channels on each steam line in a two-out-of-four logic configuration. Three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

Low Main Steam Line Pressure must be OPERABLE in MODES 1 and 2, and MODE 3 except when the operator manually controls MSRV or MSDV for cooling. This signal may be manually bypassed by the operator while performing cooling operations for shutting down with manual control of an MSRV or MSDV. This Function is not required to be OPERABLE in MODE 3 while performing those operations because the MSRV and MSRVBV can be closed by the operator. Therefore, the automatic Main Steam Relief Line Isolation on Low Main Steam Line Pressure function is not required under these conditions. When starting up, the Low Main Steam Line Pressure signal is manually enabled after completion of the manual control of MSRV or MSDV by the operator. In MODES 4, 5, and 6, the SGs are not in service and this Function is not required to be OPERABLE.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 9).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's accuracy is found non-conservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or digital bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of channels inoperable in a trip function exceeds those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

In all cases where the LCO states “Restore channel or train to OPERABLE status”, this means restore the required number of channels or trains to OPERABLE status. Therefore, restoration of an alternate channel or train, other than the failed channel or train, is also acceptable.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1, and B.2.2

Condition B applies to Manual Initiation of:

- ECCS Actuation,
- Containment Spray, and
- Containment Phase A Isolation.

ACTIONS (continued)

This action addresses the train orientation of the PSMS for the functions listed above. If one required train is inoperable, 72 hours are allowed to return it to an OPERABLE status. Note that for Containment Spray and Phase B Isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations.

The Completion Time of 72 hours is justified because (1) for ECCS two trains are adequate to perform the safety function and there are three required automatic actuation trains and two other required Manual Initiation trains OPERABLE, (2) for Containment Spray three trains are adequate to perform the safety function and there are four automatic actuation trains and three other Manual Initiation trains OPERABLE, or (3) for Containment Phase A Isolation one train is adequate to perform the safety function and there are two automatic actuation trains and one other Manual Initiation train OPERABLE. The Completion Time also considers that all trains of ECCS can be initiated by the Manual Initiation Function from the two remaining trains, and Containment Spray can be initiated by the Manual Initiation Function from any two of the three remaining trains.

In addition, the Completion Time considers that each train of all Functions can be manually initiated from the Safety VDU for that train. Therefore, manual initiation through safety related equipment remains functional in all required trains.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (78 hours total time) and in MODE 5 within an additional 30 hours (108 hours total time). The allowable 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.

ACTIONS (continued)

C.1, C.2.1, and C.2.2

Condition C applies to the Actuation Logic and Actuation Outputs for the following Functions:

- Containment Phase A Isolation, and
- Containment Phase B Isolation.

This action addresses the train orientation of the PSMS. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the remaining OPERABLE train(s) are adequate to perform the safety function. In addition, the Completion Time considers that the remaining OPERABLE train(s) each have continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows placing one train in bypass for up to 4 hours while performing surveillance testing, provided the other train(s) are OPERABLE. This 4 hour bypass time is reasonable based on operating experience that 4 hours is the average time required to perform a train surveillance.

ACTIONS (continued)

The Bypass Time of 4 hours is justified because the remaining OPERABLE train(s) are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE train(s) have continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in the FSAR Chapter 19 (Ref. 11).

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

Condition D applies to:

- High Containment Pressure, and
- High-High Containment Pressure.

If one required channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the trip condition. Failure of one channel places the Function in a two-out-of-two configuration, when the failed channel does not result in a trip channel. This configuration provides adequate plan protection, but does not meet the single failure criteria. Therefore, within 72 hours the inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies the single failure criteria.

The Completion Time of 72 hours is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

BASES

ACTIONS (continued)

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

Failure to restore the channel inoperable to OPERABLE status or place it in the trip condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one required channel in bypass for up to 12 hours while performing surveillance testing, provided the other required channels are OPERABLE, or one required channel is OPERABLE and the other required channel is placed in the trip condition.

The Bypass Time of 12 hours is justified because the remaining OPERABLE required channels are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE required channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Bypass Time of 12 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

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

Condition E applies to:

- Containment Spray - High-3 Containment Pressure, and
- Containment Phase B Isolation - High-3 Containment Pressure.

If one required channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status. Failure of one channel places the Function in a two-out-of-two configuration, when the failed channel does not result in a trip channel. This configuration provides adequate plant protection, but does not meet the single failure criteria. Therefore, within 72 hours the inoperable channel must be restored to OPERABLE status. Tripping a channel, as in Condition D, is undesirable because a single failure would then cause spurious Containment Spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented.

The Completion Time of 72 hours to restore the inoperable channel is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

Failure to restore the required number of channels to OPERABLE status within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one required channel in bypass for up to 12 hours while performing surveillance testing, provided the other required channels are OPERABLE. Bypassing with another channel in trip, as in Condition D, is undesirable because a single failure during surveillance testing would then cause spurious Containment Spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented.

Bypass Time of 12 hour is justified because the remaining OPERABLE channels are adequate to perform the safety function. In addition, the remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Bypass Time of 12 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

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

Condition F applies to Loss of Offsite Power.

BASES

ACTIONS (continued)

Condition F also applies to the Manual Initiation for:

- Main Steam Line Isolation,
- Main Feedwater Isolation,
- Emergency Feedwater Actuation,
- Emergency Feedwater Isolation,
- CVCS Isolation,
- Block Turbine Bypass and Cooldown Valves, and
- Main Steam Relief Line Isolation

For all Functions, this action addresses the train orientation of the PSMS. For the Loss of Offsite Power Function, this action also recognizes the lack of manual trip provision for a failed channel.

If one channel or required train is inoperable, 72 hours are allowed to return it to OPERABLE status.

For the Loss of Offsite Power Function, the Completion Time of 72 hours is justified because the two remaining OPERABLE undervoltage devices for each train of the Emergency Feedwater Actuation Function are adequate to perform the safety function. Since the undervoltage devices are dedicated for each of the four Class 1E busses, and two undervoltage devices are adequate to perform the safety function of each bus, the Emergency Feedwater Actuation on Loss of Offsite Power continues to meet the single failure criterion (i.e., three trains of the Emergency Feedwater Actuation Function will still actuate if there is an additional undervoltage device failure on one bus).

For Manual Initiation Functions, the Completion Time of 72 hours is justified because (1) for Emergency Feedwater Actuation the remaining two trains are adequate to perform the safety function and there are three automatic actuation trains and two other Manual Initiation trains OPERABLE, or (2) for Main Steam Line Isolation, Main Feedwater Isolation, Emergency Feedwater Isolation, CVCS Isolation, Block Turbine Bypass and Cooldown Valves, and Main Steam Relief Line Isolation the remaining train is adequate to perform the safety function and there are two automatic actuation trains and one other Manual Initiation train OPERABLE. The Completion Time also considers that Emergency Feedwater Actuation for all trains can be initiated by the Manual Initiation Function from the two remaining trains.

ACTIONS (continued)

In addition, the Completion Time for the Manual Initiation Function considers that each train can be manually initiated from the Safety VDU for that train. Therefore, manual initiation through safety related equipment remains functional in all trains.

For all Functions, the Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

For the Loss of Offsite Power Function a Note is added to allow placing one channel in bypass for up to 4 hours while performing surveillance testing, provided the other channels on the same bus are OPERABLE, or one channel is OPERABLE and the other is placed in the trip condition.

The Bypass Time of 4 hours is justified because the Function remains fully OPERABLE on every bus. In addition, the Bypass Time considers that each OPERABLE train has continuous automatic self-testing.

The 4 hour bypass time is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 5).

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

Condition G applies to the Actuation Logic and Actuation Outputs for the;

- Emergency Feedwater Isolation,
- CVCS Isolation,
- Turbine Trip Functions, and
- Main Steam Relief Line Isolation

ACTIONS (continued)

The action addresses the train orientation of the PSMS for these Functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the remaining OPERABLE train is adequate to perform the safety function. In addition, the Completion Time considers that the remaining OPERABLE train has continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing one train in bypass for up to 4 hours while performing surveillance testing, provided the other train is OPERABLE.

The Bypass Time of 4 hours is justified because the remaining OPERABLE train is adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE train has continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

H.1 and H.2

Condition H applies to the Emergency Feedwater Actuation on Trip of all MFW Pumps.

This action addresses the train orientation of the PSMS for the auto start function of the EFW System on loss of all MFW pumps. The OPERABILITY of the EFW System must be assured by allowing automatic start of the EFW System pumps.

If a required channel is inoperable, 48 hours are allowed to return it to an OPERABLE status.

The allowance of 48 hours to return the train to an OPERABLE status is justified because Trip of all Main Feedwater Pumps is an anticipatory function that is not credited in the safety analysis.

If the function cannot be returned to an OPERABLE status, 6 hours are allowed to place the unit in MODE 3.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

I.1, I.2.1, and I.2.2

Condition I applies to the P-11 interlock.

With one or more required channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function.

If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlocks.

BASES

ACTIONS (continued)

J.1 [and J.2]

Condition J applies to the Actuation Logic and Actuation Outputs for the Emergency Feedwater Actuation.

The action addresses the train orientation of the PSMS for this Functions.

If one required train is inoperable, 72 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 72 hours is justified because the two remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE trains each have continuous automatic self-testing.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

[Required Action J.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

The Required Actions are modified by a Note that allows placing one required train in bypass for up to 4 hours while performing surveillance testing, provided the other required trains are OPERABLE.

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

K.1

Condition K applies to the failure of one Containment High Range Area Radiation channel. Since the three Containment High Range Area Radiation channels measure the same parameter, failure of a single channel does not result in loss of the radiation monitoring Function for any event.

If one required channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status. Failure of one channel places the Function in a two-out-of-two configuration.

The Completion Time of 72 hours to restore the inoperable channel is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19. (Ref. 11).

BASES

ACTIONS (continued)

L.1

Condition L applies to the Containment Purge Isolation - Actuation Logic and Actuation Outputs Function and addresses the train orientation of the Engineered Safety Features Actuation System (ESFAS). Condition L also addresses the failure of multiple Containment Purge Isolation - Containment High Range Area Radiation channels, or the Required Action and associated Completion Time of Condition K not met.

If a train of Actuation Logic and Actuation Outputs is inoperable, multiple required channels of Containment High Range Area Radiation are inoperable, or the Required Action and associated Completion Time of Condition K are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

M.1 and M.2

Condition M applies to:

- Low Pressurizer Pressure,
- Low Main Steam Line Pressure,
- Low T_{avg},
- Low-Low T_{avg},
- High Pressurizer Water Level,
- High Main steam Line Pressure Negative Rate,
- High SG Water Level,
- Low SG Water Level, and
- High-High SG Water Level.

ACTIONS (continued)

With one required channel inoperable the inoperable channel must be placed in the trip condition within 1 hour and restored to OPERABLE status in 72 hours.

This Condition applies to functions that operate on two-out-of-three logic and have channels that are shared with the control systems. Failure of one channel places the Function in a two-out-of-two configuration, when the failed channel does not result in a trip channel. Normally the SSA can prevent erroneous control system operations. However, when there are less than three OPERABLE channels, the SSA cannot prevent erroneous control system operation due to an input failure. With two OPERABLE channels and one channel in the trip condition, if a channel failure occurs in an OPERABLE channel and results in erroneous control system operation, the remaining OPERABLE channel can provide a plant trip. However, the channel that causes the erroneous control system operation cannot be credited as the single failure; therefore, this configuration does not satisfy the single failure criteria. To satisfy the single failure criteria, three channels must be restored to OPERABLE status within 72 hours.

The Completion Time of 1 hour to place the failed channel in the trip condition is based on operating experience and the minimum amount of time allowed for manual operator actions.

The Completion Time of 72 hours to restore the inoperable channel is justified because the two remaining OPERABLE channels are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE channels have continuous automatic self-testing and continuous automatic CHANNEL CHECKS.

The Completion Time of 72 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19. (Ref.11).

Bypass of a required channel is not allowed because there are only three required channels and these channels are also used for control. If a failure were to occur in one of the two remaining control channels, a plant transient could occur that would require a plant trip, but a plant transient would not occur with only one remaining OPERABLE channel.

ACTIONS (continued)

N.1 and N.2

If the Required Action and associated Completion Time of Condition M are not met, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

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.

O.1 and O.2

Condition O applies to the S-VDU trains for the Manual Control of ESF Components Function.

If one train is inoperable, 72 hours are allowed to restore the train to OPERABLE status. If the inoperable S-VDU train cannot be restored to OPERABLE status, the applicable Conditions and Required Actions must be entered for ESF components made inoperable by the inoperable S-VDU train. This ensures appropriate limits are placed upon train inoperability. LCO 3.4 through 3.7 provide MODE and train requirements applicable to ESF components.

The Required Actions are modified by a Note that allows placing one train in bypass for up to 4 hours while performing surveillance testing, provided the other trains are OPERABLE. This 4 hour Bypass Time is reasonable based on operating experience that 4 hours is the average time required to perform a train surveillance.

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

BASES

ACTIONS (continued)

P.1 and P.2

Condition P applies to the COM-2 trains for the Manual Control of ESF Components Function.

If one train is inoperable, 12 hours are allowed to restore the train to OPERABLE status. If the inoperable COM-2 train cannot be restored to OPERABLE status, the applicable Conditions and Required Actions must be entered for the affected train of all ESF components made inoperable by the inoperable COM-2 train. This ensures appropriate limits are placed upon train inoperability. LCO 3.4 through 3.7 provide MODE and train requirements applicable to ESF components.

The Required Actions are modified by a Note that allows placing one train in bypass for up to 4 hours while performing surveillance testing, provided the other trains are OPERABLE. This 4 hour Bypass Time is reasonable based on operating experience that 4 hours is the average time required to perform a train surveillance.

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

Q.1 [and Q.2]

Condition Q applies to the Actuation Logic and Actuation Outputs for the following functions:

- ECCS Actuation, and
- Containment Spray.

This action addresses the train orientation of the PSMS.

BASES

ACTIONS (continued)

If one required train is inoperable, 24 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the remaining OPERABLE trains each have continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

[Required Action Q.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time. This Required Action is not applicable in MODE 4, because Risk Informed Completion Times are only applicable to MODES 1, 2 and 3.]

The Required Actions are modified by a Note that allows placing one required train in bypass for up to 4 hours while performing surveillance testing, provided the other required trains are OPERABLE. This 4 hour Bypass Time is reasonable based on operating experience that 4 hours is the average time required to perform a train surveillance.

The Bypass Time of 4 hours is justified because the remaining OPERABLE trains are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE trains have continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

R.1 and R.2

Condition R applies to the Actuation Logic and Actuation Outputs for the following functions:

- ECCS Actuation, and
- Containment Spray,

If the Required Action and associated Completion Time of Condition Q are not met, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within 6 hours and in MODE 5 within an additional 30 hours (36 hours total time). The 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.

S.1 [and S.2]

Condition S applies to the Actuation Logic and Actuation Outputs for the;

- Main Steam Line Isolation,
- Main Feedwater Isolation, and
- Block Turbine Bypass and Cooldown Valves.

The action addresses the train orientation of the PSMS for these Functions.

If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status.

The Completion Time of 24 hours is justified because the remaining OPERABLE train is adequate to perform the safety function. In addition, the Completion Time considers that the remaining OPERABLE train has continuous automatic self-testing.

The Completion Time of 24 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

BASES

ACTIONS (continued)

[Required Action S.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

The Required Actions are modified by a Note that allows placing one train in bypass for up to 4 hours while performing surveillance testing, provided the other train is OPERABLE.

The Bypass Time of 4 hours is justified because the remaining OPERABLE train is adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE train has continuous automatic self-testing.

The Bypass Time of 4 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

<u>T.1 and T.2</u>

Condition T applies to the Actuation Logic and Actuation Outputs for the following functions:

- Main Steam Line Isolation,
- Main Feedwater Isolation,
- Emergency Feedwater Actuation, and
- Block Turbine Bypass and Cooldown Valves.

Condition T applies when the Required Action and associated Completion Time for Condition J or S have not been met. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours (12 hours total time). Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions.

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.

BASES

ACTIONS (continued)

U.1

Condition U applies when one MCR Outside Air Intake Radiation monitoring channel is inoperable in one or more Functions. There are two 100% capacity MCREFS Trains A and D, with two trains required, and four 50% capacity MCRATCS Trains A, B, C and D, with three trains required. There are two channels, A and D, for each of three MCR Outside Air Intake Radiation monitoring Functions, with two channels required for each function. An inoperable MCR Outside Air Intake Radiation monitoring channel affects all MCREFS and MCRATCS trains.

If one channel for any of the MCR Outside Air Intake Radiation monitoring Functions is inoperable, the instrumentation Function of MCREFS and MCRATCS can provide 100% capacity but doesn't satisfy the single failure criterion. Therefore, within 7 days one MCREFS train and two MCRATCS trains are placed in the emergency mode. With these trains in the emergency mode, 100% capacity is provided for MCR Outside Air Intake Radiation monitoring Functions. In addition, with one OPERABLE MCR Outside Air Intake Radiation monitoring channel remaining for all Functions, an additional MCREFS train and MCRATCS train are capable of automatic initiation, therefore all MCR Outside Air Intake Radiation monitoring Functions meet the single failure criterion.

The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10 for the mechanical systems.

The emergency mode of operation requires components of the specified trains to be manually placed in the position that they would be automatically actuated to by the MCR Isolation signal. In addition, the controlled components must be configured to prevent erroneous component repositioning from spurious signals from Operational VDUs by manually activating the MCRVS O-VDU Disconnect function. This action is needed because the automatic initiation signals are credited to override any spurious Operational VDU signals, but those signals are affected in this Condition. These two actions accomplish the actuation instrumentation Function and place the unit in a conservative mode of operation.

The "emergency mode" for this Condition, is defined as the pressurization mode specified in LCO 3.7.10. Automatic transfer to the isolation mode for protection against smoke ingress [or toxic gas] is not affected by this condition.

ACTIONS (continued)

V.1, V.2.1, and V.2.2

Condition V applies when two MCR Outside Air Intake Radiation monitoring channels are inoperable in one or more Functions. There are two 100% capacity MCREFS trains, A and D, with two trains required, and four 50% capacity MCRATCS trains, A, B, C and D, with three trains required. There are two channels, A and D, for each of three MCR Outside Air Intake Radiation monitoring Functions, with two channels required for each function. Two inoperable MCR Outside Air Intake Radiation monitoring channels affect all MCREFS and MCRATCS trains.

If two MCR Outside Air Intake Radiation monitoring channels for the same Function are inoperable in one or more Functions, the MCREFS and MCRATCS instrumentation Functions are completely inoperable. Therefore, one MCREFS train and two MCRATCS trains are immediately placed in the emergency mode. With these trains in the emergency mode, 100% capacity is provided for all MCR Outside Air Intake Radiation monitoring Functions, but the system does not meet the single failure criterion.

Action must be taken within 7 days to restore compliance to the single failure criteria by either restoring one channel of each MCR Outside Air Intake Radiation monitoring Function to OPERABLE status (V.2.1), or placing two trains of MCREFS and three trains of MCRATCS in the emergency mode (V.2.2).

For V.2.1, with one MCREFS train and two MCRATCS trains in the emergency mode, and one additional train of each Function capable of automatic initiation, the system provides 100% capacity and satisfies the single failure criterion.

For V.2.2, with two trains of MCREFS and three trains of MCRATCS in the emergency mode, the system provides 100% capacity and satisfies the single failure criterion.

The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10 for the mechanical systems.

The emergency mode of operation requires components of the specified trains to be manually placed in the position that they would be automatically actuated to by the MCR Isolation signal. In addition, the controlled components must be configured to prevent erroneous component repositioning from spurious signals from Operational VDUs by manually activating the MCRVS O-VDU Disconnect function. This action is needed because the automatic initiation signals are credited to override any spurious Operational VDU signals, but those signals are affected in this

ACTIONS (continued)

Condition. These two actions accomplish the actuation instrumentation Function and place the unit in a conservative mode of operation.

The “emergency mode” for this Condition, is defined as the pressurization mode specified in LCO 3.7.10. Automatic transfer to the isolation mode for protection against smoke ingress [or toxic gas] is not affected by this condition.

W.1

Condition W applies when one train, A or D, of the MCR Isolation Actuation Logic and Actuation Outputs Function is inoperable, or one train, A or D, of the MCR Isolation Manual Initiation Function is inoperable. There are two 100% capacity MCREFS trains, A and D, with two trains required, and four 50% capacity MCRATCS trains, A, B, C and D, with three trains required. There are four Manual Initiation trains, with three trains required, including Trains A and D.

If Train A or D of the MCR Isolation Actuation Logic and Actuation Outputs Function or the MCR Isolation Manual Initiation Function is inoperable, the instrumentation of MCREFS provides 100% capacity but doesn't satisfy the single failure criterion. Therefore, within 7 days the affected train of MCREFS is placed in the emergency mode. With one train in the emergency mode the system provides 100% capacity, and with the remaining OPERABLE MCREFS train capable of automatic actuation, the system satisfies the single failure criterion for automatic actuation. In addition, with the remaining OPERABLE MCREFS train capable of Manual Initiation, the system satisfies the single failure criterion for Manual Initiation.

The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10 for the mechanical systems.

Although one instrumentation train of MCRATCS is inoperable due to inoperable Train A or D, there is no Required Action to place any train of MCRATCS in the emergency mode, since three required instrumentation trains of MCRATCS are unaffected and remain OPERABLE.

If Train B or C is inoperable, the instrumentation of MCREFS is unaffected. Although one instrumentation train of MCRATCS is inoperable, there is no Required Action to place any train of MCRATCS in the emergency mode, since three required instrumentation trains of MCRATCS are unaffected and remain OPERABLE.

The emergency mode of operation requires components of the specified train to be manually placed in the position that they would be automatically

ACTIONS (continued)

actuated by the MCR Isolation signal. In addition, when the ESFAS is inoperable (which affects automatic actuation and manual initiation), but the SLS remains OPERABLE, the controlled components must be configured to prevent erroneous component repositioning from spurious signals from Operational VDUs by manually activating the MCRVS O-VDU Disconnect function. This action is needed because the automatic actuation signals are credited to override any spurious Operational VDU signals, but those signals are affected in this Condition. These two actions accomplish the actuation instrumentation Function and place the unit in a conservative mode of operation.

[The “emergency mode” for this Condition, is defined as the pressurization mode specified in LCO 3.7.10. While operating in the pressurization mode, smoke ingress must be manually monitored and may require prompt manual transfer to the emergency isolation mode. This is because when the MCR Isolation Actuation Logic and Actuation Outputs Function is inoperable, manual transfer from the MCR to the isolation mode for smoke protection and automatic transfer to the isolation mode for smoke protection, are affected.

OR The “emergency mode” for this Condition, is defined as the isolation mode specified in LCO 3.7.10, to accommodate toxic gas protection.]

<u>X.1, X.2.1, X.2.2, X.3.1 and X.3.2</u>

Condition X applies when Trains A and D of the MCR Isolation Actuation Logic and Actuation Outputs Function are inoperable, or Trains A and D of the MCR Isolation Manual Initiation Function are inoperable. There are two 100% capacity MCREFS trains, A and D, with two trains required, and four 50% capacity MCRATCS trains, A, B, C and D, with three trains required. There are four Manual Initiation trains, with three trains required, including Trains A and D. Other inoperable two-train combinations are addressed in Condition Y.

Inoperable Trains A and D affect MCREFS and MCRATCS. The effects and required actions are as follows:

MCREFS

If two Actuation Logic and Actuation Outputs trains (A and D) are inoperable, or two MCR Isolation Manual Initiation trains (A and D) are inoperable, the MCREFS Function is completely inoperable. Therefore, one train of MCREFS is immediately placed in the emergency mode. With one train in the emergency mode MCREFS provides 100% capacity, but does not meet the single failure criterion.

BASES

ACTIONS (continued)

Action must be taken within 7 days to restore compliance to the single failure criteria by either restoring one train of MCREFS instrumentation to OPERABLE status with the other train in the emergency mode (X.2.1), or placing two trains of MCREFS in the emergency mode (X.2.2).

For X.2.1, with one train of MCREFS in the emergency mode and one train capable of automatic actuation and manual initiation, MCREFS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

For X.2.2, with two trains of MCREFS in the emergency mode, the MCREFS provides 100% capacity and satisfies the single failure criterion.

MCRATCS

If two Actuation Logic and Actuation Outputs trains (A and D) are inoperable, or if two MCR Isolation Manual Initiation trains (A and D) are inoperable, the two remaining OPERABLE instrumentation trains (B and C) of MCRATCS provide 100% capacity, but do not meet the single failure criterion.

Action must be taken within 7 days to restore compliance to the single failure criteria by either restoring one affected train of MCRATCS to OPERABLE status (X.3.1), or placing one affected train of MCRATCS in the emergency mode (X.3.2).

For X.3.1, with three trains of MCRATCS capable of automatic actuation and manual initiation, MCRATCS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

For X.3.2 with one train in the emergency mode and two trains capable of automatic actuation and manual initiation, MCRATCS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10 for the mechanical systems.

The emergency mode of operation requires components of the specified train(s) to be manually placed in the position that they would be automatically actuated to by the MCR Isolation signal. In addition, when the ESFAS is inoperable (which affects automatic and manual initiation), but the SLS

ACTIONS (continued)

remains OPERABLE, the controlled components must be configured to prevent erroneous component repositioning from spurious signals from Operational VDUs by manually activating the MCRVS O-VDU Disconnect function. This action is needed because the automatic actuation signals are credited to override any spurious Operational VDU signals, but those signals are affected in this Condition. These two actions accomplish the actuation instrumentation Function and place the unit in a conservative mode of operation.

[The “emergency mode” for this Condition, is defined as the pressurization mode specified in LCO 3.7.10. While operating in the pressurization mode, smoke ingress must be manually monitored and may require prompt manual transfer to the emergency isolation mode. This is because when the MCR Isolation Actuation Logic and Actuation Outputs Function is inoperable, manual transfer from the MCR to the isolation mode for smoke protection and automatic transfer to the isolation mode for smoke protection, are affected.

OR the “emergency mode” for this Condition, is defined as the isolation mode specified in LCO 3.7.10, to accommodate toxic gas protection.]

<u>Y.1 and Y.2</u>

Condition Y applies when two MCR Isolation Actuation Logic and Actuation Outputs trains or two MCR Isolation Manual Initiation trains are inoperable, except for inoperable Trains A and D, which are addressed in Condition X. There are two 100% capacity MCREFS trains, A and D, with two trains required, and four 50% capacity MCRATCS trains, A, B, C and D, with three trains required. There are four Manual Initiation trains, with three trains required, including Trains A and D.

The affected Functions and Required Actions depend on the inoperable trains, as follows:

- If Trains A and B, or A and C, or B and D, or C and D are inoperable, the one remaining OPERABLE instrumentation train of MCREFS and the two remaining OPERABLE instrumentation trains of MCRATCS provide 100% capacity, but they don’t meet the single failure criterion. Action must be taken within 7 days to restore compliance to the single failure criteria by either restoring the affected instrumentation train of MCREFS and one affected instrumentation train of MCRATCS to OPERABLE status (Y.1), or placing the affected train of MCREFS and one affected train of MCRATCS in the emergency mode (Y.2).

  For Y.1, with two trains of MCREFS and three trains of MCRATCS capable of automatic actuation and manual initiation, MCREFS and

ACTIONS (continued)

MCRATCS provide 100% capacity and satisfy the single failure criterion for automatic actuation and manual initiation.

For Y.2, with one train of MCREFS in the emergency mode and one train capable of automatic actuation and manual initiation, MCREFS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation. With one train of MCRATCS in the emergency mode and two trains capable of automatic actuation and manual initiation, MCRATCS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

- If trains B and C are inoperable, the instrumentation of MCREFS is unaffected. The two remaining OPERABLE instrumentation trains of MCRATCS provide 100% capacity, but do not meet the single failure criterion.

  Action must be taken within 7 days to restore compliance to the single failure criteria by either restoring one affected instrumentation train of MCRATCS to OPERABLE status (Y.1) or placing one affected train of MCRATCS in the emergency mode (Y.2).

  For Y.1, with three trains of MCRATCS capable of automatic actuation or manual initiation, MCRATCS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

  For Y.2, with one train of MCRATCS in the emergency mode and two trains capable of automatic actuation and manual initiation, MCRATCS provides 100% capacity and satisfies the single failure criterion for automatic actuation and manual initiation.

The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10 for the mechanical systems.

The emergency mode of operation requires components of the specified train(s) to be manually placed in the position that they would be automatically actuated to by the MCR Isolation signal. In addition, when the ESFAS is inoperable (which affects automatic actuation and manual initiation), but the SLS remains OPERABLE, the controlled components must be configured to prevent erroneous component repositioning from spurious signals from Operational VDUs by manually activating the MCRVS O-VDU Disconnect function. This action is needed because the automatic actuation signals are credited to override any spurious Operational VDU signals, but those signals are affected in this Condition. These two actions accomplish the actuation

ACTIONS (continued)

instrumentation Function and place the unit in a conservative mode of operation.

[The “emergency mode” for this Condition, is defined as the pressurization mode specified in LCO 3.7.10. While operating in the pressurization mode, smoke ingress must be manually monitored and may require prompt manual transfer to the emergency isolation mode. This is because when the MCR Isolation Actuation Logic and Actuation Outputs Function is inoperable, manual transfer from the MCR to the isolation mode for smoke protection and automatic transfer to the isolation mode for smoke protection, are affected.

OR the “emergency mode” for this Condition, is defined as the isolation mode specified in LCO 3.7.10, to accommodate toxic gas protection.]

<u>Z.1 and Z.2</u>

Condition Z applies when the Required Action and associated Completion Time for Condition U, V, W, X or Y have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and 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.

<u>AA.1</u>

Condition AA applies when the Required Action and associated Completion Time for Condition U, V, W, X or Y have not been met when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require MCR Isolation actuation.

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

Condition BB applies to the P-4 Interlock.

This action addresses the train orientation of the PSMS.

If a required train is inoperable, 48 hours are allowed to restore the train to OPERABLE status.

BASES

ACTIONS (continued)

The Completion Time of 48 hours is justified because the two remaining OPERABLE trains are adequate to perform the safety function. In addition, the Completion Time considers that the two remaining OPERABLE trains each have continuous automatic self-testing.

The Completion Time of 48 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

If the train cannot be restored to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the interlock function noted above.

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

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies all trains of the ESFAS. However, when testing a channel, it is only necessary to manually verify that the channel is OPERABLE in its respective division. This is because the interface to other divisions is automatically verified through continuous automatic self-testing. Continuous automatic self-testing is confirmed through periodic MIC. The CHANNEL CALIBRATION is performed in a manner that is consistent with the methods and assumptions of Specification 5.5.21, Setpoint Control Program (SCP).

SR 3.3.2.1

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

Agreement criteria are determined based on a combination of the channel instrument uncertainties. 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.

[The Surveillance Frequency of 12 hours is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

A CHANNEL CHECK may be conducted manually or automatically. For the US-APWR an automated CHANNEL CHECK is normally conducted continuously, which satisfies the 12 hour Surveillance Frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria is not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum 12 hour Surveillance Frequency.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.2.2</u>

SR 3.3.2.2 is the performance of a MIC for the ESFAS Instrumentation. This includes the Safety VDU processors, the RPS, the ESFAS, the SLS, and the COM-2.

The PSMS is self-tested automatically on a continuous basis from the digital side of all input modules to the digital side of all output modules. Continuous automatic self-testing encompasses all PSMS safety-related functions including digital Nominal Trip Setpoints, Time Constants, Time Delays and actuation logic functions. The continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. The continuous automatic self-testing is described in Reference 6 and Reference 7.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The MIC is a diverse check of the PSMS software memory integrity, consistent with the Setpoint Control Program (SCP), to ensure there is no change to the internal PSMS software that would impact its functional operation, including digital Nominal Trip Setpoints, Time Constants, Time Delays, actuation logic functions or the continuous automatic self-testing. The MIC is described in Reference 6 and Reference 7.

The capability to generate continuous automatic self-testing fault alarms shall be confirmed OPERABLE during the MIC.

The complete OPERABILITY check from the measurement channel input device to the SLS output device is performed by the combination of the continuous automatic self-testing for the digital devices (the RPS, ESFAS, SLS, and data communication interfaces), the continuous automatic CHANNEL CHECK (SR 3.3.2.1), the CHANNEL CALIBRATION (SR 3.3.2.6), the MIC (SR 3.3.2.2), and the TADOT (SR 3.3.2.3, SR3.3.2.4, SR 3.3.2.5 and SR 3.3.2.8). The CHANNEL CALIBRATION, the MIC, and the TADOT, which are manual tests, overlap with the continuous automatic self-testing and confirm the functioning of the continuous automatic self-testing.

The complete OPERABILITY check from the Safety VDU (S-VDU) input device to the SLS output device is performed by the combination of the continuous automatic self-testing for the digital devices (Safety VDU processors, COM-2, SLS and data communication interfaces), the SAFETY VDU TEST (SR 3.3.2.9), MIC for the Safety VDU processors, COM-2 and SLS (SR 3.3.2.2) and TADOT for SLS outputs (SR 3.3.2.3). The SAFETY VDU TEST, MIC, and TADOT, which are manual tests, overlap with the automatic self-testing and confirm the functioning of the automatic tests.

[The Surveillance Frequency of 24 months is justified because the software memory integrity is checked by the continuous automatic self-testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency of 24 months is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 11).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.2.3

SR 3.3.2.3 is the performance of a TADOT for the Actuation Outputs of all ESFAS Functions, and the Actuation Outputs of the Manual Control of ESF Components Function. This surveillance test actuates the outputs of the SLS.

Therefore, this test is typically conducted in conjunction with testing the plant process components. Since this test is conducted in conjunction with testing for plant process components, this test may be conducted more frequently, as may be required for the plant process components.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data of solid state Actuation Output devices.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4

SR 3.3.2.4 is the performance of a TADOT for the Loss of Offsite Power, Function. The LOP inputs to the ESFAS are tested up to, and including, the signal status readout on a VDU.

Verification of the undervoltage relay Nominal Trip Setpoint is not performed during the TADOT; the undervoltage relay Nominal Trip Setpoint is verified during CHANNEL CALIBRATION.

[The Surveillance Frequency of 92 days is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.2.5

SR 3.3.2.5 is the performance of a TADOT for all Manual Initiation Functions and for the EFW Actuation - Trip of all MFW Pumps Function. Each Function is tested up to, and including, the signal status readout on a VDU. These Functions have no associated setpoints.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience and is consistent with the typical refueling cycle.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.6

SR 3.3.2.6 is the performance of a CHANNEL CALIBRATION.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test must be performed consistent with the methods and assumptions of Specification 5.5.21, SCP, to verify that the channel responds to a measured parameter within the necessary range and accuracy.

The CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital VDU readout, as described in Reference 6.

For analog measurements, the CHANNEL CALIBRATION confirms the calibration settings are within the Allowable Value at multiple points over the entire measurement channel span, encompassing all ESF actuation and interlock Nominal Trip Setpoint values. Digital ESF actuation and interlock Nominal Trip Setpoint values are confirmed through MIC.

For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel's state change. The state change must occur within the Allowable Value of the Nominal Trip Setpoint.

The equipment that performs the automated CHANNEL CHECK shall be confirmed OPERABLE, including the capability to generate fault alarms during the CHANNEL CALIBRATION.

[The Surveillance Frequency of 24 months is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with Specification 5.5.21, Setpoint Control Program (SCP).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

This SR ensures the ESF RESPONSE TIME is less than or equal to the maximum value assumed in the accident analysis. Accident analysis response time values are specified in Reference 2. Individual component response times are not modeled in the analyses.

The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Analytical Limit to the point at which the equipment in the minimum credited train(s) reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel.

Allocations for sensors, signal conditioning and actuation logic response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The PSMS MELTAC controllers employ dynamic transfer functions with Time Constants and actuation logic functions with Time Delays that are installed as digital values and processed through digital algorithms. Therefore, the time response of all digital PSMS functions has no potential for variation due to time, environmental drift or component aging. PSMS Time Constants and Time Delays are set at the nominal values assumed in the safety analysis. The combination of continuous automatic self-testing and MIC confirms the integrity of the dynamic transfer functions, Time Constants, Time Delays and actuation logic functions.

The response time for the digital portion of the PSMS is determined one time by analysis and confirmed one time in the factory test. Therefore, for PSMS digital functions, including Functions with Time Constants and Time Delays, response time tests are not required; instead, a response time allocation may be applied.

Response time for PSMS MELTAC input signal conditioning, can be affected by random failures or degradation, which can be detected by CHANNEL CALIBRATION. Section 4.6 of MUAP-07005, “Safety System Digital Platform -MELTAC-” (Ref. 7) describes the basis for crediting CHANNEL CALIBRATION for detecting PSMS signal conditioning response time degradation. Therefore, for PSMS input signal conditioning, response time tests are not required; instead, a response time allocation may be applied.

BASES

SURVEILLANCE REQUIREMENTS (continued)

MUAP-09021-P, “Response Time of Safety I&C System” (Ref. 8), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the report. Response time verification for other sensor types must be demonstrated by test. MUAP-09021-P also provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. In addition, MUAP-09021-P identifies the acceptance criteria for ESFAS components that require response time measurement (such as LOOP undervoltage relays which are known to have aging or wear-out mechanisms that can impact response time), taking into consideration the total ESF RESPONSE TIME requirement and the allocations for other components that do not require testing.

The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

[ESF RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. The 24 month Surveillance Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that clarifies that the tests for the turbine driven EFW pumps are conducted within 24 hours after reaching 1000 psig in the SGs.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT for the P-4 Interlock. The Surveillance Frequency is once per RTB cycle, as required by SR 3.3.1.4. Each RTB status contact is tested up to, and including, the signal status readout on a digital VDU. This Surveillance Frequency is based on operating experience demonstrating that undetected failure of the P-4 interlock sometimes occurs when the RTB is cycled.

The P-4 Interlock has no associated setpoint.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a SAFETY VDU TEST for the Safety VDUs in the MCR. The SAFETY VDU TEST is explained in Reference 6.

This SR confirms the Safety VDU is capable of providing all display and control functions for the MCR. This SR overlaps with the MIC (SR 3.3.2.2), to ensure the S-VDU is OPERABLE.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data. In addition, the Surveillance Frequency considers that all indications and controls for each safety train and channel are available in the MCR on non-safety Operational VDUs.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

REFERENCES

1. NUREG-0737, “Clarification of TMI Action Plan Requirements.”
2. FSAR Section 7.3.
3. FSAR Chapter 15.
4. IEEE-603-1991.
5. 10 CFR 50.49.
6. MUAP-07004-P , Revision 7, “Safety I&C System Description and Design Process.”
7. MUAP-07005-P , Revision 8, “Safety System Digital Platform -MELTAC-.”
8. MUAP-09021-P, Revision 3, “Response Time of Safety I&C System.”
9. 10 CFR 50.36.
10. FSAR Section 15.7.4.
11. FSAR Chapter 19.
12. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”
13. Regulatory Guide 1.105, Revision 3, “Setpoints for Safety Related Instrumentation.”
14. FSAR Chapter 9.4.1.2.2.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The purpose of displaying PAM parameters is to assist Main Control Room (MCR) personnel in evaluating the safety status of the plant. PAM parameters are direct measurements or derived variables representative of the safety status of the plant. The primary function of the PAM parameters is to aid the operator in the rapid detection of abnormal operating conditions. As an operator aid, the PAM variables represent a minimum set of plant parameters from which the plant safety status can be assessed.

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

The availability of accident monitoring 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 instruments are identified by FSAR Section 7.5 (Ref. 4) addressing the recommendations of Regulatory Guide 1.97 (Ref. 1) as required by Supplement 1 to NUREG-0737 (Ref. 2).

The instrument channels required to be OPERABLE by this LCO include parameters based on IEEE 497-2002 (Ref. 5), which is endorsed by Regulatory Guide 1.97 (Ref. 1), identified as Type A, B and C variables.

FSAR Section 7.5 (Ref. 4) describes the PAM Instrumentation, and in particular, the process that was used for determining the bounding list of PAM variables in Table 3.3.3-1.

Type A, B, and C variables are the key variables deemed risk significant because they are needed to:

Type A

Take planned manually controlled actions for accomplishment of safety-related functions for which there is no automatic control.

Type B

Assess the process of accomplishing or maintaining plant critical safety functions.

Type C

Indicate potential for a breach of fission product barriers.

BASES

BACKGROUND (continued)

Indicate an actual breach of fission product barriers.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM Instrumentation ensures the operability of Type A, B and C 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 Postulated Accidents), e.g., loss of coolant accident (LOCA),
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function,
- Determine whether systems important to safety are performing their intended functions,
- Determine the likelihood of 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 and to estimate the magnitude of any impending threat.

The PAM Instrumentation is interfaced to the Protection and Safety Monitoring System (PSMS) through the Reactor Protection System (RPS), with the exception of Containment Isolation Valve (CIV) position, which is interfaced via the Safety Logic System (SLS). The RPS, including Nuclear Instrumentation System (NIS), and SLS provide signal conditioning, analog to digital conversion, and digital signals for display of the PAM Instrumentation measurements on MCR VDUs.

The PAM Instrumentation is displayed in the MCR via Safety VDUs and non-safety Operational VDUs. Only the Safety VDUs are credited for the PAM Display Function. The S-VDU in each train consists of a VDU and S-VDU processor.

To meet the single failure criteria and accommodate on-line maintenance, four trains of S-VDU, RPS and SLS are provided, each performing the same functions. If one train is taken out of service for maintenance or test purposes, the remaining trains will provide PAM displays for the unit.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The S-VDU, RPS and SLS for each train are packaged in their own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The S-VDU, RPS and SLS have continuous automatic self-testing while in service. When any one train is taken out of service for manual testing, the remaining trains are capable of providing unit monitoring and protection until the testing has been completed.

LCO

The LCO requires all instrumentation performing the PAM Instrumentation Function, listed in Table 3.3.3-1 in the accompanying LCO, to be OPERABLE. A channel is OPERABLE provided the "as-found" value, measured during surveillance testing, does not exceed its associated Allowable Value, and provided the “as-left” value is within the specified calibration tolerance at the completion of each CHANNEL CALIBRATION.

The PAM Instrumentation LCO provides OPERABILITY requirements for Type A variables, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses instruments that have been designated Type B and C.

The OPERABILITY of the PAM Instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident.

The number of channels available for PAM Instrumentation Functions is shown in FSAR Chapter 7 Table 7.5-3. For PAM Instrumentation Functions with two channels, the channels are assigned to Trains A and D; both channels are required. For PAM Instrumentation Functions with four channels, the channels are assigned to Trains A, B, C and D; the required number of which is two, three, or four depending on the variable.

LCO 3.3.3 requires two, three or four OPERABLE channels. The specified number of OPERABLE channels ensures no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

BASES

LCO (continued)

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

The exception to the minimum two channel requirement is Penetration Flow Path Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indication 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 a 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.

Due to redundant components within the PSMS, such as controllers, communication links and power supplies, an inoperable component may or may not result in an inoperable channel. Where an inoperable component results in an inoperable required channel, LCOs are entered. For inoperable components that do not result in inoperable channels, LCOs are not entered.

Table 3.3.3-1 provides a list of the PAM variables.

Type A, B and C variables are required to meet requirements defined in IEEE 497-2002 (Ref. 5) for seismic and environmental qualification, and testability. Type A, B and C variables must also meet requirements for single failure criterion, separation and independence, quality, utilization of emergency standby power, information ambiguity and recording of display. In addition, Type A and B variables require continuously visible displays. These design features are described in Chapter 7 (Ref. 4).

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

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

   Wide Range Neutron Flux indication is provided to verify reactor shutdown. A single wide range instrument for each channel covers the full range of flux that may occur post accident.

   Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

BASES

LCO (continued)

2, 3. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

Verification of core cooling can be determined by RCS Hot or Cold Leg Temperature in any one RCS loop. The Emergency Operating Procedure (EOP) operator action threshold points, for events such as steam generator tube rupture, can only be determined by RCS Hot Leg Temperature in any one RCS loop.

There is one channel each of RCS Hot Leg Temperature (Wide Range) and RCS Cold Leg Temperature (Wide Range) per loop and a minimum of any three loops are required for each parameter. Therefore, in any one loop both instruments may be OPERABLE (i.e., RCS Hot Leg and Cold Leg Temperature) or only one instrument may be OPERABLE (i.e., RCS Hot Leg or Cold Leg Temperature).

Only three channels are required for each parameter because if the break is in one of the instrumented loops, the instrumentation in either remaining instrumented loop (i.e., RCS Hot Leg Temperature or RCS Cold Leg Temperature) provides sufficient indication of core cooling, and the EOP operator action threshold points can be confirmed by the RCS Hot Leg Temperature instrumentation in either remaining instrumented loop. Therefore, with only 3 required channels for each parameter (each monitoring any three loops), a single failure affecting one or both instruments (i.e., RCS Hot leg Temperature/RCS Cold Leg Temperature) in any intact loop can be accommodated.

LCO (continued)

4. Reactor Coolant System Pressure (Wide Range)

RCS Pressure (Wide Range) is provided for verification of core cooling and RCS integrity long term surveillance.

5. Reactor Vessel Water Level

Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy. There are two channels and two channels are required. A channel consists of three sections with two sensors per section. A channel is OPERABLE if at least one sensor is OPERABLE in all three sections.

6. Containment Pressure

Containment Pressure is provided for verification of RCS and containment OPERABILITY and is used to verify closure of main steam isolation valves (MSIVs) and Phase B Containment Isolation when High-3 Containment Pressure is reached. Additionally, Containment Pressure is provided for indication of maintaining RCS integrity and containment integrity.

7. Containment Isolation Valve Position

Penetration Flow Path CIV Position is provided for verification of Containment OPERABILITY, and Phase A and Phase B Isolation.

When used to verify Phase A and Phase B Isolation, the important information is the isolation status of the containment penetrations. 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) in Table 3.3.3-1 requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a 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.

LCO (continued)

Note (a) in Table 3.3.3-1 states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

Each penetration is treated separately and each penetration flow path is considered a separate function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

8. Containment High Range Area Radiation

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

9. Pressurizer Water Level

Pressurizer Water Level is used to determine whether to terminate ECCS Actuation, if still in progress, or to reinitiate ECCS Actuation if it has been stopped. Pressurizer Water Level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

10,11. Steam Generator Water Level (Wide Range and Narrow Range)

SG Water Level is provided to monitor operation of decay heat removal via the SGs.

SG Water Level (Narrow Range) is used to:

- identify the faulted SG following a tube rupture,
- verify that the intact SGs are an adequate heat sink for decay heat removal from the reactor,
- determine the nature of the accident in progress (e.g., verify an SGTR), and
- verify unit conditions for termination of ECCS Actuation during secondary unit HELBs outside containment.

BASES

LCO (continued)

Operator action is based on the control room indication of SG level. The RCS response during a design basis small break LOCA depends on the break size. For a certain range of break sizes SGs are necessary to remove decay heat. SG Water Level (Narrow Range) can be used to manually control SG level to remove decay heat via the SGs.

SG Water Level (Wide Range), which covers the span above the lower tubesheet, is used to verify that the intact SGs are an adequate heat sink for decay heat removal from the reactor.

There is one SG Water Level (Wide Range) channel per loop. All four loops are required because if the break is in one of the instrumented SGs and there is a single failure affecting the instrumentation in another SG, the instrumentation in the remaining two SGs provide sufficient indication of heat sink availability; two SGs are required for sensible heat removal.

BASES

LCO (continued)

12, 13, 14, 15. <u>Core Exit Temperature</u>

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

For Post Accident Monitoring, twenty six core exit thermocouple channels are provided for measuring core cooling. The thermocouple channels are arranged in two safety trains, A and D, with each train consisting of thirteen thermocouple channels. A minimum of 2 thermocouple channels from each of two trains (4 total) are required for each core quadrant. For each train and each core quadrant, one thermocouple channel is required near the center of the core and one thermocouple channel is required near the core perimeter. The two thermocouple channels indicate the radial temperature gradient across their core quadrant. The uniform distribution of thermocouple channels from both trains ensures adequate information of radial temperature distribution even with a single train failure condition.

16. <u>Emergency Feedwater Flow</u>

Emergency Feedwater (EFW) Flow is provided to monitor operation of decay heat removal via the SGs.

EFW flow is used three ways:

- to verify delivery of EFW flow to the SGs,
- to determine whether to terminate ECCS Actuation if still in progress, in conjunction with SG Water Level (Narrow Range), and
- to verify that the intact SGs are an adequate heat sink for decay heat removal from the reactor.

LCO (continued)

There is one channel of EFW Flow per loop. All four loops are required, because if the break is in one of the instrumented SGs and there is a single failure affecting the instrumentation in another SG, the instrumentation in the remaining two SGs provide sufficient indication of heat sink availability; two SGs are required for sensible heat removal.

17. Degrees of Subcooling

Degrees of Subcooling is provided for verification of core cooling. Degrees of Subcooling utilizes sensors for RCS Cold and Hot Leg Temperatures, Core Exit Temperature and RCS Pressure. The saturation temperature is calculated from the pressure input. The temperature subcooled margin is the difference between the calculated saturation temperature and the sensor temperature input. Two temperature subcooled margin presentations are available as follows:

- RCS saturation margin – The temperature saturation margin is based on the difference between the saturation temperature and the maximum temperature from the RTDs in the hot and cold legs.

- Upper head saturation margin – The temperature saturation margin is based on the difference between the saturation temperature and the Core Exit Temperature.

18. Main Steam Line Pressure

Steam Generator Pressure is provided to monitor decay heat removal via the SGs.

19. Emergency Feedwater Pit Level

EFW Pit Level is provided to ensure water supply for Emergency Feedwater (EFW). The EFW Pits provide the ensured safety grade water supply for the EFW System. There are two identical EFW Pits, each of which supplies one motor driven and one turbine driven EFW pump. Redundant level indication for each EFW Pit is displayed in the Main Control Room.

LCO (continued)

20,21. Refueling Water Storage Pit (RWSP) Level (Wide Range, Narrow Range)

RWSP Level is provided for verification and long term surveillance of RCS integrity and is used to determine:

- RWSP level accident diagnosis, and
- Whether to terminate ECCS Actuation, if still in progress.

PAM Display Function

The PAM Display Function is provided by four trains of Safety VDUs (S-VDU). A Safety VDU train consists of a VDU and S-VDU processor. An S-VDU train must be OPERABLE for the corresponding channels of the required PAM Instrumentation Functions, and in the same MODES. For PAM Instrumentation Functions with four channels (two or three required channels), two or three corresponding S-VDU trains must be OPERABLE. For PAM Instrumentation Functions with only two required channels, two corresponding S-VDU trains must be OPERABLE. For CIV position, there are two-train components assigned to Trains A and D, and two-train components assigned to Trains B and C. Therefore, because all four trains are required for CIV position, all four trains of S-VDU are required to be OPERABLE.

APPLICABILITY

The PAM Instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate PAs. The applicable PAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM Instrumentation is low; therefore, the PAM Instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

The ACTIONS Table has been modified by a Note to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1 and the PAM Display Function. 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.

In all cases where the LCO states “Restore channel or train to OPERABLE status”, this means restore the required number of channels or trains to OPERABLE status. Therefore, restoration of an alternate channel or train, other than the failed channel or train, is also acceptable.

BASES

ACTIONS (Continued)

A.1

Condition A applies when one or more PAM Instrumentation Functions have one required channel inoperable, or one train of the PAM Display Function is inoperable.

Required Action A.1 requires restoring the inoperable channel or train to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel(s) or trains (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (operability for automatic actions that may occur from these instruments is covered by LCOs in other sections), and the low probability of an event requiring PAM Instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.5, which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1 [and C.2]

Condition C applies when one or more PAM Instrumentation Functions have two required channels inoperable, or two trains of the PAM Display Function are inoperable.

BASES

ACTIONS (Continued)

Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two trains or 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 or train of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

[Required Action C.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.

Required Action C.2 is modified by a Note that indicates C.2 may only be performed when the Emergency Feedwater Pit Level is inoperable.]

<u>D.1 and D.2</u>

If the Required Action and associated Completion Time of Condition C are not met, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 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

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM Instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

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

Agreement criteria are determined based on a combination of the channel instrument uncertainties. 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.

[The Surveillance Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SURVEILLANCE REQUIREMENTS (continued)

A CHANNEL CHECK may be conducted manually or automatically. For the US-APWR an automated CHANNEL CHECK is normally conducted continuously, which satisfies the 31 day Surveillance Frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria is not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum 31 day Surveillance Frequency.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test must be performed consistent with the methods and assumptions of MUAP-09022, "US-APWR Instrument Setpoint Methodology" (Ref. 6), to verify that the channel responds to a measured parameter with the necessary range and accuracy.

The CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital VDU read out as described in Reference 3.

For analog measurements, except Core Exit Temperature Channels, CHANNEL CALIBRATION confirms the channel accuracy at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range.

For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel's state change at the required setpoint.

This SR includes the RCS Hot Leg and Cold Leg Temperature channels. The CHANNEL CALIBRATION of the RCS Hot Leg and Cold Leg Temperature channels is accomplished by a cross calibration that compares the signals from the installed channels to a channel with a reference RTD, in accordance with FSAR Section 7.1.3.14 (Ref. 8).

SURVEILLANCE REQUIREMENTS (continued)

This SR includes the Core Exit Temperature channels. The CHANNEL CALIBRATION of the Core Exit Temperature channels is accomplished by a cross calibration that compares the signals from the installed channels to the signals from the RCS Hot Leg and Cold Leg Temperature channels, after they have been calibrated as described above.

This SR is modified by a Note that excludes the neutron detectors from the CHANNEL CALIBRATION for the Wide Range Neutron Flux channels; the remaining channel devices are included. The calibration method for neutron detectors is specified in the Bases for SR 3.3.1.9 of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

The equipment that performs the automated CHANNEL CHECK shall be confirmed OPERABLE, including the capability to generate fault alarms during the CHANNEL CALIBRATION.

[The Surveillance Frequency of 24 months is based on operating experience, and on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with MUAP-09022, “US-APWR Instrument Setpoint Methodology”, and is consistent with the typical industry refueling cycle.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.3.3</u>

SR 3.3.3.3 is the performance of a MEMORY INTEGRITY CHECK (MIC) for the PAM Instrumentation. This includes the Safety VDU processors, RPS and SLS.

The PSMS is self-tested automatically on a continuous basis from the digital side of all input modules to the digital side of all visual display units. Continuous automatic self-testing encompasses all PSMS safety-related functions. The continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. The continuous automatic self-testing is described in Reference 3 and Reference 7.

SURVEILLANCE REQUIREMENTS (continued)

The MIC is a diverse check of the PSMS software memory integrity to ensure there is no change to the internal PSMS software that would impact its functional operation, including the continuous automatic self-testing. The MIC is described in Reference 3 and Reference 7.

The capability to generate continuous automatic self-testing fault alarms shall be confirmed OPERABLE during the MIC.

The complete OPERABILITY check from the measurement channel input device to the Safety VDU is performed by the combination of the continuous automatic self-testing for the digital devices (the Safety VDU processors, RPS, SLS and data communication interfaces), the continuous automatic CHANNEL CHECK (SR 3.3.3.1), the CHANNEL CALIBRATION (SR 3.3.3.2) and the MIC (SR 3.3.3.3). The CHANNEL CALIBRATION, the MIC, and the TADOT, which are manual tests, overlap with the continuous automatic self-testing and confirm the functioning of the continuous automatic self-testing.

[The Surveillance Frequency of 24 months is justified because the software memory integrity is checked by the continuous automatic self-testing.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.3.4</u>

SR 3.3.3.4 is the performance of a SAFETY VDU TEST for the Safety VDUs in the MCR. The SAFETY VDU TEST is explained in Reference 3.

This SR confirms the Safety VDU is capable of providing all display functions for the MCR. This test overlaps with the MIC (SR 3.3.3.3), to ensure the S-VDU is OPERABLE.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data.

In addition, the Surveillance Frequency considers that all indications and controls for each safety train and channel are available in the MCR on six other non-safety Operational VDUs.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES

1. Regulatory Guide 1.97, Rev. 4.

2. NUREG-0737, “Clarification of TMI Action Plan Requirements.”

3. MUAP-07004-P, Revision 7, “Safety I&C System Description and Design Process.”

4. FSAR Section 7.5.

5. IEEE 497-2002.

6. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”

7. MUAP-07005-P, Revision 8, “Safety System Digital Platform -MELTAC-.”

8. FSAR Section 7.1.3.14.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown Console (RSC)

BASES

BACKGROUND

The RSC provides sufficient displays and controls for the Main Control Room (MCR) operator to place and maintain the unit in a hot standby condition (MODE 3), to place and maintain the unit in a hot shutdown condition (MODE 4), and to place and maintain the unit in a cold shutdown condition (MODE 5), from a location outside the MCR if the MCR becomes inaccessible. In accordance with Section 7.4 (Ref. 4), MODES 3, 4 or 5 are referred to as safe shutdown.

With the unit in MODE 3, the Emergency Feedwater (EFW) System and the steam generator (SG) safety valves or the main steam depressurization valves (MSDVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the EFW System and the ability to borate the Reactor Coolant System (RCS) from outside the MCR allows extended operation in MODE 3.

If the MCR becomes inaccessible, the operators can establish control at the RSC, and place and maintain the unit in MODE 3 for an extended period of time. The RSC also provides the capability to transition and maintain the unit in MODE 5, using the Residual Heat Removal System.

APPLICABLE SAFETY ANALYSES

The RSC is located outside the MCR with the capability to promptly shutdown, cooldown and maintain the unit in a safe condition in MODE 3, and the capability to transition and maintain the unit in a safe condition in MODE 4 or 5, in accordance with the design described in FSAR Section 7.4 (Ref. 4).

The criteria governing the design and specific system requirements for remote shutdown are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1). These criteria are applied to the RSC of the US-APWR.

The RSC satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

The RSC LCO provides the OPERABILITY requirements for the RSC, which includes the displays and controls necessary to place and maintain the unit in MODE 3, with the capability to transition to MODES 4 or 5 and the ability to transfer control from the MCR to the RSC.

LCO

Due to redundant components within the PSMS, such as controllers, communication links and power supplies, an inoperable component may or may not result in an inoperable channel or train. Where an inoperable component results in an inoperable required channel or train, LCOs are entered. For inoperable components that do not result in inoperable channels or trains, LCOs are not entered. The instrumentation required are listed in Table B 3.3.4-1.

LCO (continued)

Display and Control Function

The displays and controls at the RSC are functionally the same as the displays and controls used by the operator to achieve and maintain MODE 3, 4 or 5 from the MCR. These displays and controls are provided by four trains of Safety VDUs, and non-safety Operational VDUs. MODE 3, 4 or 5 can be achieved and maintained using only safety related plant equipment which is controlled and monitored from Safety VDUs or Operational VDUs.

The Display and Control Function of the RSC encompasses the measurement channels and component controls required for safe shutdown, and the subsystems of the PSMS that support that equipment. The measurement channels and component controls available to achieve normal and safe shutdown are identified in Table 7.4-1 and Table 7.4-2 of FSAR Section 7.4 (Ref. 4).

The measurement channels for safe shutdown, that are required to be OPERABLE for this LCO, are listed in Table B 3.3.4-1, including the required number of channels. These measurement channels are interfaced to the Reactor Protection System (RPS) and then provided to the RSC. Each item listed in Table B 3.3.4-1 is referred to as an RSC Instrumentation Function.

The component controls for safe shutdown, that are required to be OPERABLE for this LCO, are listed in Table B 3.3.4-2, including the required number of trains. The Safety Logic System (SLS) provides the Actuation Logic and Actuation Outputs for these components. Safe shutdown can be achieved by only one train of plant equipment for two train ESF systems and by two trains of plant equipment for four train ESF systems. One additional train is required to meet the single failure criteria. Each item listed in Table B 3.3.4-2 is referred to as an RSC Control Function.

The Display and Control Function also encompasses the Safety VDUs (S-VDU) and Communication Subsystem (COM-2). The S-VDU is required for the display of safe shutdown measurement channels. The S-VDU and COM-2 are required for manual control of safe shutdown components. Since for all required safe shutdown systems, the required OPERABLE safety plant components may be distributed to all four trains, all four trains of Safety VDUs and COM-2 are required. The Safety VDU in each train consists of a VDU and Safety VDU processor.

All plant equipment, including non-safety plant equipment is controlled and monitored from the Operational VDUs at the RSC. This equipment is provided for convenience and is not necessary to achieve or maintain MODE 3, 4 or 5. Therefore the Operational VDUs are not covered by this LCO.

LCO (continued)

The RSC equipment covered by this LCO does not need to be continuously energized to be considered OPERABLE. However, it is necessary to energize this equipment for surveillance testing.

Transfer of Control Function

The controls in the MCR are normally enabled, while the controls at the RSC are normally disabled. Actuation of Transfer Switches disables the controls in the MCR and enables the controls at the RSC. There are two Transfer Switches for each safety train of the Protection and Safety Monitoring System (PSMS) (8 switches) and two Transfer Switches for the Plant Control and Monitoring System (PCMS) (which has only one train). Activating both Transfer Switches for a train, transfers the controls for that train. Transferring control also blocks signals from the disabled location that could otherwise interfere with safe shutdown operations. Since all trains must be capable of control transfer and signal blocking, both Transfer Switches for all four PSMS trains and the PCMS are required to be OPERABLE.

The Transfer of Control Function also encompasses the COM-2. The COM-2 is required for transfer of control from the MCR to the RSC. Since for all required safe shutdown systems, the required OPERABLE safety plant components may be distributed to all four trains, all four trains of COM-2 are required.

APPLICABILITY

The RSC LCO is applicable in MODES 1, 2 and 3. This applicability recognizes the need for being able to place and maintain the unit in a safe shutdown condition (MODE 3, with the capability to transition to MODES 4 or 5) from a location outside the MCR if the MCR becomes inaccessible while the RCS contains a large amount of energy.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if MCR instruments or controls become unavailable.

ACTIONS

In all cases where the LCO states “Restore channel or train to OPERABLE status”, this means restore the required number of channels or trains to OPERABLE status. Therefore, restoration of an alternate channel or train, other than the failed channel or train, is also acceptable.

A.1

Condition A addresses the situation where one required channel or train for the Display and Control Function is inoperable, or one train for the Transfer of Control Function is inoperable.

The Required Action is to restore the channel or train to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the MCR.

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time of Condition A are not met. In this condition, 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 6 hours and to MODE 4 within 12 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 3.3.4.1

SR 3.3.4.1 is the performance of a TADOT for the Transfer of Control Function from the MCR to the RSC, which verifies the RSC Transfer Switches perform their required functions for each PSMS train and the PCMS. Each Transfer Switch is tested up to, and including, the signal status readout on a digital display.

This SR verifies that the controls and interfaces for the Transfer of Control Function are OPERABLE.

[The 24 month Surveillance Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data. Allowing this test during unit outage conditions is reasonable given the robustness of the Transfer Switches and the potential for unplanned transients if performed at power.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2

SR 3.3.4.2 is the performance of a SAFETY VDU TEST for all Safety VDUs on the RSC. The SAFETY VDU Test is explained in Reference 3.

This SR confirms the Safety VDU is capable of providing all Display and Control Functions for the RSC. This test overlaps with the MEMORY INTEGRITY CHECK (MIC) for the Safety VDU processor (SR 3.3.4.5), to ensure the Display and Control Function is OPERABLE.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data. In addition, the Surveillance Frequency considers that all indications and controls for each safety train and channel are available on two other non-safety Operational VDUs.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.4.3

SR 3.3.4.3 is the performance of a CHANNEL CHECK for each RSC Instrumentation Function in Table 3.3.4-1.

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

SURVEILLANCE REQUIREMENTS (continued)

[The Surveillance Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

A CHANNEL CHECK may be conducted manually or automatically. For the US-APWR an automated CHANNEL CHECK is normally conducted continuously, which satisfies the 31 day Surveillance Frequency requirement. Where the CHANNEL CHECK is conducted automatically, an alarm shall be generated when the agreement criteria is not met. If the automated CHANNEL CHECK function is unavailable, a manual CHANNEL CHECK shall be conducted at the minimum 31 day Surveillance Frequency.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.4.4</u>

SR 3.3.4.4 is the performance of a CHANNEL CALIBRATION for each RSC Instrumentation Function in Table B 3.3.4-1.

The CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital VDU readout, as described in Reference 3.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test must be performed consistent with the methods and assumptions of MUAP-09022, “US-APWR Instrument Setpoint Methodology” (Ref. 6), to verify that the channel responds to a measured parameter with the necessary range and accuracy.

For analog measurements, CHANNEL CALIBRATION confirms the channel accuracy at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range. For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel’s state change at the required setpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is applicable to all channels, including the Wide Range Neutron Flux channels. However, this SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases for SR 3.3.1.9 of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

This SR includes the RCS Hot Leg and Cold Leg Temperature channels. The calibration of the channels is accomplished by a cross calibration that compares the signals from the installed channels to a channel with a reference RTD, in accordance with FSAR Section 7.1.3.14 (Ref. 7).

The equipment that performs the automated CHANNEL CHECK shall be confirmed OPERABLE, including the capability to generate fault alarms during the CHANNEL CALIBRATION.

[The Surveillance Frequency of 24 months is based on operating experience, and on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with MUAP-09022, “US-APWR Instrument Setpoint Methodology”, and is consistent with the typical industry refueling cycle.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.4.5

SR 3.3.4.5 is the performance of a MIC for the RSC. This includes the Safety VDU processors, RPS, SLS and COM-2.

The PSMS is self-tested automatically on a continuous basis from the digital side of all input modules to the digital side of all output modules. Continuous automatic self-testing encompasses all PSMS safety-related functions including actuation logic functions. The continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. The continuous automatic self-testing is described in Reference 3 and Reference 5.

SURVEILLANCE REQUIREMENTS (continued)

The MIC is a diverse check of the PSMS software memory integrity to ensure there is no change to the internal PSMS software that would impact its functional operation, including actuation logic functions or the continuous automatic self-testing. The MIC is described in Reference 3 and Reference 5.

The capability to generate continuous automatic self-testing fault alarms shall be confirmed OPERABLE during the MIC.

The complete operability check from the Safety VDUs (S-VDU) input device to the Safety Logic System (SLS) output device is performed by the combination of the continuous automatic self-testing for the digital devices (Safety VDU processors, COM-2, SLS and digital communication interfaces), the SAFETY VDU TEST (SR 3.3.4.2), MIC for the Safety VDU processors, COM-2 and SLS (SR 3.3.4.5) and TADOT for SLS outputs (SR 3.3.4.6). The SAFETY VDU TEST, MIC, and TADOT, which are manual tests, overlap with the continuous automatic self-testing and confirm the functioning of the continuous automatic self-testing.

The complete operability check from the measurement channel sensing device to the S-VDU is performed by the combination of the continuous automatic self-testing for the digital devices (Safety VDU processors and RPS, and digital communication interfaces), the SAFETY VDU TEST (SR 3.3.4.2), MIC for the Safety VDU processors and RPS (SR 3.3.4.5), the continuous automatic CHANNEL CHECK (SR 3.3.4.3) and the CHANNEL CALIBRATION (SR 3.3.4.4). The CHANNEL CALIBRATION, MIC and Safety VDU TEST, which are manual tests, overlap with the continuous automatic self-testing and confirm the functioning of the continuous automatic self-testing.

[The Surveillance Frequency of 24 months is justified because the software memory integrity is checked by the continuous automatic selftesting.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.6

SR 3.3.4.6 is the performance of a TADOT for the Actuation Outputs of each required train for each RSC Control Function. This test actuates the outputs of the SLS for all components required to achieve and maintain safe shutdown. Therefore, this test is typically conducted in conjunction with testing the plant process components. Since this test is conducted in conjunction with testing for plant process components, this test may be conducted more frequently, as may be required for the plant process components.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data of solid state Actuation Output devices.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. 10 CFR 50.36.
3. MUAP-07004-P, Revision 7, “Safety I&C System Description and Design Process.”
4. FSAR Section 7.4.
5. MUAP-07005-P, Revision 8, “Safety System Digital Platform – MELTAC.”
6. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”
7. FSAR Section 7.1.3.14.

Table B 3.3.4-1 (Sheet 1 of 2)
Remote Shutdown Console Instrumentation

FUNCTION	REQUIRED NUMBER OF CHANNELS
1. Reactor Coolant System	
a. Pressurizer Water Level	2
b. Pressurizer Pressure	2
c. Reactor Coolant Hot Leg Temperature (Wide Range)	3
d. Reactor Coolant Cold Leg Temperature (Wide Range)	3
e. Reactor Coolant Pressure	2
2. Safety Injection System	
a. Safety Injection Pump Discharge Flow	1 per Required Pump
b. Safety Injection Pump Minimum Flow	1 per Required Pump
c. Safety Injection Pump Discharge Pressure	1 per Required Pump
d. Safety Injection Pump Suction Pressure	1 per Required Pump
e. Accumulator Pressure	1 per Tank
3. Residual Heat Removal System	
a. CS/RHR Hx Outlet Temperature	1 per Required Pump
b. CS/RHR Pump Discharge Flow	1 per Required Pump
c. CS/RHR Pump Minimum Flow	1 per Required Pump
d. CS/RHR Pump Discharge Pressure	1 per Required Pump
e. CS/RHR Pump Suction Pressure	1 per Required Pump
4. EFW Pit Water Level	
a. EFW Pit Water Level	2 per Pit
b. EFW Flow	1 per SG
c. EFW Pump Discharge Pressure	1 per Required Pump
5. Condensate and Feedwater System	
SG Water Level (Wide Range)	1 per SG

Table B 3.3.4-1 (Sheet 2 of 2)
Remote Shutdown Console Instrumentation

FUNCTION	REQUIRED NUMBER OF CHANNELS
6. Main Steam Supply System	
a. Main Steam Line Pressure	2 per Line
7. Component Cooling Water System	
a. CCW Surge Tank Water Level	1 per Required Tank Compartment
b. CCW Header Pressure	1 per Required Pump
c. CCW Header Flow	1 per Required Pump
d. CCW Supply Temperature	1 per Required Pump
e. CCW Pump Discharge Pressure	1 per Required Pump
8. Essential Service Water System	
a. CCW Hx ESW Flow	1 per Required Pump
b. ESW Header Pressure	1 per Required Pump
9. Refueling Water Storage System	
a. RWSP Water Level (Wide Range)	2
10. Nuclear Instrumentation	
a. Source Range Neutron Flux	2
[11. UHS Instrumentation	1 per Required Pump]

Table B 3.3.4-2 (Sheet 1 of 3)
Remote Shutdown Console Control

FUNCTION	REQUIRED NUMBER OF TRAINS
1. Reactor Trip System	
a. Reactor Trip Breaker	3 (2 Breakers per Train)
2. Reactor Coolant System	
a. Safety Depressurization Valve	2
b. Safety Depressurization Valve Block Valve	2
c. Pressurizer Heater Backup Group	3
d. Reactor Vessel (RV) Vent Valve	2 per Line
3. Chemical Volume Control System	
a. Seal Water Return Line Isolation Valve	2 per Line
4. Safety Injection System	
a. Safety Injection Pump (SIP)	3
b. SIPs Suction Isolation Valve	1 per Required Pump
c. SIPs Discharge Containment Isolation Valve	1 per Required Pump
d. Direct Vessel Safety Injection Line Valve	1 per Required Pump
e. Emergency Letdown Line Isolation Valve	2 per Line
f. Accumulator Discharge Valve	1 per Tank
g. ACC Nitrogen Supply Line Isolation Valve	1 per Tank
h. ACC Nitrogen Discharge Valve	2 per Tank
5. Residual Heat Removal System	
a. CS/RHR Pump	3
b. CS/RHR Pump Hot Leg Isolation Valve	1 per Required Pump (2 Valves per train)
c. CS/RHR Pumps RWSP Suction Isolation Valve	1 per Required Pump
d. RHR Discharge Line Containment Isolation Valve	1 per Required Pump
e. RHR Flow Control Valve	1 per Required Pump
f. CS/RHR Pump Full-Flow Test Line Stop Valve	1 per Required Pump

Table B 3.3.4-2 (Sheet 2 of 3)
Remote Shutdown Console Control

FUNCTION	REQUIRED NUMBER OF TRAINS
6. Emergency Feedwater System	
a. EFW Pump (Motor-Driven or Turbine Driven)	3
b. EFW Control Valve	1 per SG
c. EFW Isolation Valve	1 per SG
d. T/D-EFW Pump MS Line Steam Isolation Valve	1 per Required Pump
e. T/D-EFW Pump Actuation Valve	1 per Required Pump
7. Main Steam Supply System	
a. Main Steam Depressurization Valve	1 per SG
b. Main Steam Relief Valve Block Valve	1 per SG
c. Main Steam Isolation Valve	1 per SG
d. Main Steam Bypass Isolation Valve	1 per SG
8. Component Cooling Water System	
a. CCW Pump	3
b. CS/RHR Hx CCW Outlet 1st Valve	1 per Required Pump
c. CS/RHR Hx CCW Outlet 2nd Valve	1 per Required Pump
9. Essential Service Water System	
a. ESW Pump	3
b. ESW Pump Discharge Valve	1 per Required Pump
10. Steam Generator Blowdown System	
a. SGBD Line Containment Isolation Valve	1 per SG
b. SGBD Line Isolation Valve	1 per SG
c. SGBD Sampling Line Containment Isolation Valve	1 per SG
11. Heating, Ventilation, and Air Conditioning	
a. MCR Air Handling Unit & Damper	3
b. Class 1E Electrical Room Air Handling Unit & Damper	3

Table B 3.3.4-2 (Sheet 3 of 3)
Remote Shutdown Console Control

FUNCTION	REQUIRED NUMBER OF TRAINS
c. Class 1E Electrical Room Return Air Fan	3
d. Class 1E Battery Room Exhaust Fan & Damper	3
e. Class 1E Electrical Room In-duct heater	3
f. CCW Pump Area Air Handling Unit	3
g. Essential Chiller Unit Area Air Handling Unit	3
h. EFW Pump Area Air Handling Unit	3
i. Essential Chiller Unit	3
j. Essential Chilled Water Pump & Valves	3
[12. UHS Components	3]

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Class 1E Gas Turbine Generator (GTG) Start Instrumentation

BASES

BACKGROUND

The Class 1E GTGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs in the switchyard. There are four LOP start signals, one for each 6.9 kV Class 1E bus.

<u>Field Sensors</u>

Three undervoltage relays with inverse time characteristics are provided on each 6.9 kV Class 1E bus for detecting a sustained degraded voltage condition or a loss of bus voltage. Signals from the undervoltage relays are interfaced to the ESFAS.

<u>ESFAS and SLS</u>

Signals from the undervoltage relays are combined in a two-out-of-three actuation logic within the ESFAS to generate an LOP signal when the voltage is dropped before reaching the loss of voltage limit for a short time or before reaching the degraded voltage limit for a long time. The LOP signal is interfaced from the ESFAS via internal digital data communication to the SLS controllers of the PSMS, which provide the GTG actuation logic, GTG control system and GTG control output. The GTG actuation logic combines manual and automatic start demands, with other GTG control interlocks; the GTG control system provides continuous closed loop control of the GTG via the GTG control output. The LOP start actuation is described in Reference 1.

<u>Allowable Values and LOP Class 1E GTG Start Instrumentation Setpoints</u>

The Nominal Trip Setpoint and Allowable Value are recorded and maintained in a document established by the Setpoint Control Program (SCP).

BACKGROUND(continued)

The Allowable Value in conjunction with the Nominal Trip Setpoint and LCO establishes the threshold for Engineered Safety Features Actuation System (ESFAS) action to prevent exceeding acceptable limits such that the consequences of Postulated Accidents (PAs) will be acceptable. The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value during the CHANNEL CALIBRATION (Ref. 7). Note that although a channel is OPERABLE under these circumstances, the setpoint shall be left adjusted to within the established Calibration Tolerance band of the setpoint in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left-criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned. The Calibration Tolerance is recorded and maintained in a document established by the SCP.

If the as-found value of the device is found to have exceeded the Allowable Value, or the as-left value of the device cannot be adjusted to the value within the Calibration Tolerance, the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

Setpoints adjusted consistent with the requirements of Specification 5.5.21, SCP ensure that the consequences of accidents will be acceptable, provided the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed. The time required to start the Class 1E GTG, which is initiated by the LOP signal, is considered in the analysis presented in FSAR Chapter 15 (Ref. 6).

The Nominal Trip Setpoint entered into the LOP binary sensor is more conservative than that specified by the Analytical Limit. The Nominal Trip Setpoint accounts for measurement errors detectable by the CHANNEL CALIBRATION and other unmeasurable errors (such as the effects of anticipated environmental conditions), which are both considered in the Allowable Value for the LOP Nominal Trip Setpoint, which is checked during CHANNEL CALIBRATION. If the as-found value of the LOP setpoint does not exceed the Allowable Value, the channel is considered OPERABLE. Operation with a trip setpoint less conservative than the Nominal Trip Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation.

BASES

BACKGROUND(continued)

Within the Protection and Safety Monitoring System (PSMS), LOP Time Delays are digital settings maintained in non-volatile software memory within each ESFAS train. Digital settings have no potential for variation due to time, environmental drift or component aging; therefore, these digital settings have no surveillance tolerance. Each train of the process control equipment has continuous automatic self-testing, which verifies that the digital Time Delay settings are correct. Time Delays are also verified periodically through a diverse software MEMORY INTEGRITY CHECK (MIC).

APPLICABLE SAFETY ANALYSES

The LOP Class 1E GTG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS). Accident analyses credit the loading of the Class 1E GTG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual Class 1E GTG start has historically been associated with the ESFAS actuation. The Class 1E GTG loading has been included in the delay time associated with each safety system component requiring Class 1E GTG supplied power following a loss of offsite power. The analyses assume a non-mechanistic Class 1E GTG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP Class 1E GTG start instrumentation, in conjunction with the ESF systems powered from the Class 1E GTGs, provide unit protection in the event of any of the analyzed accidents discussed in Chapter 15, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the Class 1E GTG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation," include the appropriate Class 1E GTG loading and sequencing delay.

The LOP Class 1E GTG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

The Loss of Power (LOP) Class 1E Gas Turbine Generator (GTG) Start Instrumentation shall be OPERABLE for each bus that is required to be OPERABLE.

The LCO for LOP Class 1E GTG start instrumentation requires three OPERABLE channels per required bus of both the loss of voltage and degraded voltage Functions in MODES 1, 2, 3, and 4.

For MODES 5 and 6, three channels per required bus of both the loss of voltage and degraded voltage Functions shall be OPERABLE whenever the associated GTG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown" to ensure that the automatic start of the GTG is available when needed.

In addition, for each required bus, the LCO for LOP Class 1E GTG Start Instrumentation requires the ESFAS actuation logic, GTG actuation logic, GTG control system and GTG control output in the associated train of the ESFAS and SLS to be OPERABLE. These logic, control and output functions are collectively referred to as the LOP Actuation Function. There are four trains for the LOP Actuation Function, one train for each bus and its associated GTG.

Loss of the LOP Class 1E GTG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the Class 1E GTG powers the motor driven Emergency Feedwater Pumps. Failure of these pumps to start would leave two turbine driven pumps, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

Due to redundant components within the PSMS, such as controllers, communication links and power supplies, an inoperable component may or may not result in an inoperable channel or train. Where an inoperable component results in an inoperable required channel or train, LCOs are entered. For inoperable components that do not result in inoperable channels or trains, LCOs are not entered.

The LOP GTG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. This Function is also required in MODE 5 or 6 whenever the required GTG must be OPERABLE so that it can perform its function on an LOP or degraded power to its associated bus.

ACTIONS

In the event a channel Nominal Trip Setpoint is found non-conservative with respect to the Allowable Value, or the channel or train is found inoperable, then the function that channel or train provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. 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.

In all cases where the LCO states “Restore channel or train to OPERABLE status”, this means restore the required number of channels or trains to OPERABLE status. Therefore, restoration of an alternate channel or train, other than the failed channel or train, is also acceptable.

A.1

Condition A applies to the LOP Class 1E GTG Start Instrumentation Functions with one loss of voltage or one degraded voltage channel per required Class 1E 6.9 kV bus inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP Class 1E GTG start instrumentation channels are configured to provide a one-out-of-two logic to initiate a trip of the incoming offsite power.

BASES

ACTIONS (Continued)

The Completion Time of 6 hours is justified because the two remaining OPERABLE undervoltage devices for each bus are adequate to perform the safety function. Since the undervoltage devices are dedicated for each of the four Class 1E busses, and two undervoltage devices are adequate to perform the safety function of each bus, the LOP Class 1E GTG Start Instrumentation Function continues to meet the single failure criterion (i.e., three GTGs will still actuate if there is an additional undervoltage device failure on one bus).

The Completion Time of 6 hours is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 5).

A Note is added to allow placing one channel in bypass for up to 4 hours while performing surveillance testing, provided the other channels on the same bus are OPERABLE, or one channel is OPERABLE and the other is placed in the trip condition.

The Bypass Time of 4 hours is justified because the remaining OPERABLE channels are adequate to perform the safety function. In addition, the Bypass Time considers that the remaining OPERABLE channels have continuous automatic self-testing.

The 4 hour Bypass Time is also justified in the US-APWR reliability and risk analyses, the summary and result of which are documented in FSAR Chapter 19 (Ref. 5).

B.1

Condition B applies when two or more loss of voltage or two or more degraded voltage channels per required Class 1E 6.9 kV bus are inoperable.

Required Action B.1 requires restoring all but one channel per required Class 1E 6.9 kV bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

C.1

Condition C applies when one train of the LOP Actuation Function is inoperable for a required bus, or when the Required Action and associated Completion Time for Condition A or B are not met.

BASES

ACTIONS (Continued)

In these circumstances the Condition(s) specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the Class 1E GTG made inoperable by failure of the LOP Class 1E GTG Start Instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT for the LOP undervoltage relays and their interface to the ESFAS. For these tests, the undervoltage relays are confirmed to actuate with reasonable proximity to the Nominal Trip Setpoints. Undervoltage trip setpoint Allowable Values are verified during CHANNEL CALIBRATION (SR 3.3.5.2). Undervoltage Time Delays, which are implemented in the ESFAS, are verified during MIC (SR 3.3.5.3) for the ESFAS.

[The Surveillance Frequency of 31 days is based on the known reliability of the relays and binary input devices for the PSMS, and the multi-channel redundancy available, and has been shown to be acceptable through operating experience.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

CHANNEL CALIBRATION for a binary measurement is a complete check of the instrument loop, including the sensor and interface to the PSMS, as described in Reference 2. The test verifies that the channel responds to measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION confirms the accuracy of the channel from sensor to digital Visual Display Unit (VDU) readout, as described in Reference 2. The CHANNEL CALIBRATION confirms the accuracy of the channel's state change at the required setpoint.

CHANNEL CALIBRATIONS must be performed consistent with the methods and assumptions in Specification 5.5.21, SCP. For binary measurements, the CHANNEL CALIBRATION confirms the accuracy of the channel's state change. The state change must occur within the Allowable Value of the Nominal Trip Setpoint. Time Delays associated with Loss of Voltage and Degraded Voltage are recorded and maintained in a document established by the Setpoint Control Program (SCP) and confirmed through MIC.

[The Surveillance Frequency of 24 months is based on operating experience and is consistent with the typical industry refueling cycle. The Surveillance Frequency of 24 months is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in accordance with Specification 5.5.21, SCP.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The equipment that performs the automated CHANNEL CHECK shall be confirmed OPERABLE, including the capability to generate fault alarms during the CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

SR 3.3.5.3 is the performance of a MIC for the LOP Class 1E GTG Start Instrumentation. This includes the ESFAS and the SLS.

The PSMS is self-tested automatically on a continuous basis from the digital side of all input modules to the digital side of all output modules. Continuous automatic self-testing encompasses all PSMS safety-related functions including Time Delays, actuation logic functions and continuous control functions. The continuous automatic self-testing also encompasses all data communications within a PSMS train, between PSMS trains and between the PSMS and PCMS. The continuous automatic self-testing is described in Reference 2 and Reference 3.

The MIC is a diverse check of the PSMS software memory integrity, consistent with the Setpoint Control Program (SCP), to ensure there is no change to the internal PSMS software that would impact its functional operation, including digital Time Delays, actuation logic functions, continuous control functions or the continuous automatic self-testing. The MIC is described in Reference 2 and Reference 3.

The capability to generate continuous automatic self-testing fault alarms shall be confirmed OPERABLE during the MIC.

The complete OPERABILITY check from the measurement channel input device to the Safety Logic System (SLS) output device is performed by the combination of the continuous automatic self-testing for the digital devices (the ESFAS, SLS and data communication interfaces), the TADOT (SR 3.3.5.1) and CHANNEL CALIBRATION (SR 3.3.5.2) for the LOP undervoltage relays, the MIC (SR 3.3.5.3) and the TADOT for the GTG control output of the SLS (SR 3.3.5.4). The CHANNEL CALIBRATION, MIC, and TADOTs, which are manual tests, overlap with the continuous automatic

BASES

SURVEILLANCE REQUIREMENTS (continued)

self-testing and confirm the functioning of the automatic tests. The MIC is described in Reference 2 and Reference 3.

[The Surveillance Frequency of 24 months is justified because the software memory integrity is checked by the continuous automatic self-testing.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.3.5.4</u>

SR 3.3.5.4 is the performance of a TADOT for the GTG control outputs of the SLS.

The scope of this TADOT is limited to the GTG control outputs of the SLS, including the interface of those outputs to the GTG. However, this test is typically conducted in conjunction with testing the complete GTG, including the fuel system and other GTG engine components, in accordance with LCO 3.8.1. Since this test is conducted in conjunction with testing the GTG components, this test may be conducted more frequently, as may be required for the GTG components.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience, considering instrument reliability and operating history data of solid state control output devices.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. FSAR Section 8.3.1.

2. MUAP-07004-P, Revision 7, “Safety I&C System Description and Design Process.”

3. MUAP-07005-P, Revision 8, “Safety System Digital Platform -MELTAC-.”

4. 10 CFR 50.36.

5. FSAR Chapter 19.

6. FSAR Chapter 15.

7. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”

B 3.3 INSTRUMENTATION

B 3.3.6 Diverse Actuation System (DAS) Instrumentation

BASES

BACKGROUND

The Diverse Actuation System (DAS) provides non-Class 1E backup controls in case of beyond design basis common-cause failure (CCF) of the digital I&C systems. CCF is a condition that concurrently affects all safety and non-safety systems that contain the same digital software. CCF is considered for the Protection and Safety Monitoring System (PSMS) and the Plant Control and Monitoring System (PCMS). The DAS is not credited for mitigating accidents in the FSAR Chapter 15 (Ref. 6) analyses.

To initiate Reactor Trip, the DAS uses equipment that is diverse from the PSMS equipment (hardware and software) that is used to initiate a Reactor Trip. This diversity does not include the analog input sensors or analog signal distribution devices.

To initiate ESF functions including Turbine Trip, the DAS uses equipment that is diverse from the PSMS software. This diversity does not include the analog input sensors or analog signal distribution devices, or the final solid state Actuation Outputs in the PSMS, which are referred to as Power Interface (PIF) modules.

The DAS includes manual and automatic initiation capability.

Defense-in-Depth and Diversity (Ref.1) and FSAR Section 7.8 (Ref. 3) provide a description of the DAS.

The DAS Instrumentation is segmented into four distinct but interconnected modules as described in the Defense-in-Depth and Diversity report (Ref. 1) and FSAR Section 7.8 (Ref. 3), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured. The DAS shares field transmitters and process sensors, and signal distribution devices with the PSMS.

2. The Diverse Automatic Actuation Cabinet (DAAC): provides signal conditioning, analog bistables for setpoint comparison, process algorithm actuation, compatible electrical signal output to actuation devices, and control room indications. DAAC outputs provide the means to actuate the Rod Drive Motor-Generator Set Trip Devices which interrupt power from the Rod Drive Motor-Generator sets for Reactor Trip. DAAC outputs also provide the means to actuate Turbine Trip and other ESF functions, through the Power Interface modules of the PSMS. There are four DAACs. Each is referred to as a DAAC subsystem.

BACKGROUND (continued)

3. Diverse Human System Interface Panel (DHP): provides indications, alarms and Manual Initiation controls for DAS.

4. The Rod Drive Motor-Generator Set Trip Devices are actuated by output signals from the DAACs to interrupt power from the Rod Drive Motor-Generator Sets for Reactor Trip.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, four field transmitters or sensors are used to measure each unit parameter. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint and Allowable Values. The OPERABILITY of each channel from the transmitter or sensor through the signal distribution device is determined by "as-found" and “as-left” calibration data evaluated during the CHANNEL CALIBRATION, and by the channel behavior observed during performance of the CHANNEL CHECK. Since all DAS measurement channels are shared with the PSMS, the PSMS CHANNEL CALIBRATION and CHANNEL CHECK also confirm OPERABILITY of the DAS instrumentation from the transmitter or sensor through the signal distribution device.

DAAC Process Control Equipment

For each DAS automatic actuation function, four channels of process control equipment are used in each DAAC subsystem for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, output signals for instruments located on the DHP, and analog comparison of measured input signals with setpoints established by the D3 Coping Analysis (Ref. 2). These analog setpoints are recorded and maintained in a document established by the Setpoint Control Program (SCP). If the measured value of a unit parameter exceeds the predetermined setpoint, a binary output from a DAAC analog bistable is forwarded to the DAAC voting logic for decision evaluation. Channels are isolated in the PSMS prior to their interface to the DAAC subsystems.

In each DAAC subsystem four channels with two-out-of-four logic are provided for each parameter. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-three logic. If one channel fails, such that a partial Function trip occurs, a spurious trip will not occur and the Function is still OPERABLE

BASES

BACKGROUND (continued)

with a one-out-of-three logic. Two channels are necessary to generate a trip or ESF actuation, and since the DAS needs to function with a concurrent fire or flood in any PSMS I&C equipment room, which is where these signals originate, three channels are required. A channel of process control equipment consists of the signal path from field transmitter or sensor through the analog bistable in each DAAC.

The DAAC includes provisions to bypass a failed channel to prevent spurious trip or actuation conditions.

The measurement channels are designed such that testing may be accomplished while the reactor is at power and without causing trip or actuation. Four measurement channels are provided for each function, which allows one channel to be taken out of service with no operational restrictions.

The OPERABILITY of the DAAC process control equipment is determined by a CHANNEL OPERATIONAL TEST (COT) and by an ACTUATION LOGIC TEST. The COT overlaps with the CHANNEL CALIBRATION and the ACTUATION LOGIC TEST overlaps with the COT. OPERABILITY of the interface from each DAAC to the PSMS PIF modules and to the Rod Drive Motor-Generator Set Trip Devices is determined by a TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT), which overlaps with the ACTUATION LOGIC TEST.

Allowable Values and DAS Setpoints

The CHANNEL CALIBRATION verifies the accuracy of the measurement channels at five calibration settings corresponding to 0%, 25%, 50%, 75% and 100% of the instrument range. If the as-found value of the device is found to have exceeded the Allowable Value, or the as-left value of the device cannot be adjusted to a value within the Calibration Tolerance, the device would be considered inoperable from a technical specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required. Since DAS measurement channels are shared with the PSMS, the PSMS Reactor Trip or ESFAS Functions establish the accuracy requirements for the channel, including the Allowable Value and Calibration Tolerance for CHANNEL CALIBRATION.

BASES

BACKGROUND (continued)

Regulatory guidance (Ref. 8) allows best estimate methods for analysis that demonstrate adequate coping for Anticipated Operational Occurrences (AOOs) and Postulated Accidents (PA) with concurrent CCF. Therefore, the Nominal Trip Setpoints used in the DAAC analog bistables are the analytical limits specified in the D3 Coping Analysis (Ref. 2), with no channel uncertainty and no safety margin, in accordance with the setpoint methodology (Ref. 7). This results in analog setpoints that are less conservative than the corresponding digital setpoints in the PSMS to ensure the PSMS actuates first. If the PSMS actuates, DAS actuation is blocked. For plant operators, DAS actuation is indicative of an accident with a concurrent CCF in the PSMS, which prompts the use of special emergency procedures for beyond design basis plant conditions. Therefore, avoiding unnecessary DAS actuation is an important design basis consideration.

The selection of the DAS analytical limits and corresponding trip setpoints is such that adequate protection is provided when sensor and processing time delays are taken into account. The Allowable Value for the Nominal Trip Setpoint serves as the Technical Specification OPERABILITY limit for the purpose of the COT. Since the Nominal Trip Setpoints for DAS are set at the analytical limits in the D3 Coping Analysis (Ref. 2), the Allowable Value is established only to identify unexpected measurement error. One example of measurement error is drift during the surveillance interval. If the as-found value does not exceed the Allowable Value, the analog bistable is considered OPERABLE.

The Nominal Trip Setpoint is the value at which the analog bistable is set and is the expected value to be achieved during COT. The Nominal Trip Setpoint value ensures the D3 Coping Analysis (Ref. 2) limits are met when a channel is properly adjusted. A DAS analog bistable is considered to be properly adjusted when the "as-left" value is within the specified calibration tolerance around the Nominal Trip Setpoint.

BASES

BACKGROUND (continued)

OPERABLE channels, with calibration settings and Nominal Trip Setpoints consistent with the requirements of the Allowable Value ensure that the consequences of AOOs and PAs will be acceptable, provided the unit is operated from within the LCOs at the onset of the AOO or PA and the equipment functions as designed. The calibration setting Allowable Values, and the Nominal Trip Setpoints and corresponding Allowable Values, are recorded and maintained in a document established by the SCP. The setpoint methodology identified in the SCP (Ref. 7), is used to calculate the Allowable Values and Nominal Trip Setpoints.

The “expected as-found value” shall be as specified in the plant-specific setpoint analysis. The expected as-found value reflects the expected normal drift of actual plant equipment, so that a degraded device can be identified before the Allowable Value limit is reached. The expected as-found value is also referred to as the Performance Test Acceptance Criteria (PTAC). The PTAC, recorded and maintained in a document established by the SCP, is applicable to DAS automatic trip and actuation Functions.

Each channel of the process control equipment can be tested while in service to verify that the measurement channel signal or analog bistable setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, the field transmitter or sensor is stimulated or a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

<u>DAAC Actuation Logic and Actuation Outputs</u>

There are four DAAC subsystems. Each DAAC subsystem processes each of the four measurement channels from the PSMS through separate analog bistables. The DAAC Actuation Logic processes the outputs from the DAAC analog bistables through two-out-of-four voting logic. The outputs from the voting logic for one or more parameters are combined to generate the DAAC outputs for Reactor Trip, Turbine Trip and ESF actuation.

The DAAC subsystems also process the signals and generate the Actuation Outputs for the Manual Initiation and Manual Control Functions. For Functions that have both automatic and manual signals, the signals are combined in each DAAC subsystem to generate a common Actuation Output.

BASES

BACKGROUND (continued)

To prevent spurious actuation and loss of the functions due to one DAAC subsystem failure, the output signals from four DAAC subsystems, each performing the same function, are combined in a two-out-of-two voting logic after taking one-out-of-two voting logic twice. If the same Function outputs are generated from a selective two DAAC subsystems (i.e., DAAC1 or DAAC3, concurrent with DAAC2 or DAAC4), a Reactor Trip, Turbine Trip and/or ESF actuation will result.

The DAS needs to function with a concurrent fire or flood in any PSMS I&C equipment room, which is were these subsystems are located. All four DAAC subsystems are required because the outputs of the DAAC subsystems are configured in a selective two-out-of-four configuration, not a full two-out-of-four configuration.

The subsystems are designed such that testing may be accomplished while the reactor is at power and without causing Reactor Trip, Turbine Trip or ESF actuation. If one subsystem is actuated for maintenance or test purposes, DAS Functions for Reactor Trip, Turbine Trip or ESF actuation are maintained for the unit. Each DAAC subsystem is packaged in its own cabinet to satisfy physical separation requirements. The system has been designed to not trip or actuate in the event of a loss of power, to prevent spurious actuation.

The DAAC performs the decision logic for actuating a Reactor Trip, Turbine Trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the Main Control Room (MCR) of the unit.

BACKGROUND (continued)

The OPERABILITY of the DAAC Actuation Logic Function is determined by an ACTUATION LOGIC TEST. The ACTUATION LOGIC TEST overlaps with the COT.

The OPERABILITY of DAAC Actuation Outputs for ESF functions and Turbine Trip, which interface from each DAAC to the PIF modules in the PSMS, is determined by a TADOT (SR 3.3.6.5) which overlaps with the ACTUATION LOGIC TEST. When PIF modules are actuated, either during the ESFAS Instrumentation TADOT (SR 3.3.2.3) or for testing or control of ESF plant components, the Safety Logic System (SLS) output signals overlap with the DAAC output signals within the PIF modules.

The OPERABILITY of DAAC Actuation Outputs for Reactor Trip, which interface from each DAAC to the Rod Drive Motor-Generator Set Trip Devices, and the OPERABILITY of the Rod Drive Motor-Generator Set Trip Devices themselves, is determined by a TADOT (SR 3.3.6.6) which overlaps with the ACTUATION LOGIC TEST.

Rod Drive Motor-Generator Set Trip Devices

The Rod Drive Motor-Generator sets are the electrical power supply for the control rod drive mechanisms (CRDMs). Actuating the Rod Drive Motor-Generator Set Trip Devices interrupts power to the CRDMs, which allows the control rod shutdown banks and control banks to fall into the core by gravity. There are two Rod Drive Motor-Generator Sets operating in parallel to power all rods. Each has its own Rod Drive Motor-Generator Set Trip Device. The DAS trips both Rod Drive Motor-Generator Set Trip Devices.

The DAS interfaces to the Rod Drive Motor-Generator Set Trip Devices are via hardwired circuits. Actual tripping of each Motor-Generator Set and the associated DAS interface may be tested one at a time, with no Reactor Trip. Actual tripping of each Rod Drive Motor-Generator Set may be tested from the DAS.

BACKGROUND (continued)

Diverse Human System Interface Panel (DHP)

The DHP provides Manual Initiation switches for all DAS automatic actuation functions and for additional functions that are required, per the D3 Coping Analysis (Ref. 2), to control all critical safety functions. Manual Initiation and Control switches are not redundant. To prevent spurious actuation due to a failure of any of the above switches, a separate manual actuation Permissive Switch is provided. This is referred to as the “Permissive Switch for DAS HSI.”

The Manual Initiation and Manual Control switches interface to DAAC subsystems 1 and 3, and the Permissive Switch for DAS HSI interface to DAAC subsystems 2 and 4. Manual Initiation/Control signals and Permissive signals are combined with automatic actuation signals to generate the same DAS outputs. Therefore, as for automatic signals, if the same Manual Initiation/Control Function outputs are generated from a selective two DAAC subsystems (i.e., DAAC1 or DAAC3, concurrent with DAAC2 or DAAC4), a Reactor Trip, Turbine Trip and/or ESF actuation will result.

The OPERABILITY of the DHP Manual Initiation/Control and Permissive switches, including the interface to the DAAC subsystems and the interface from the DAAC subsystems to the PSMS PIF modules, is determined by a TADOT (SR 3.3.6.5). The OPERABILITY of the DHP Manual Initiation/Control and Permissive switches, including the interface to the DAAC subsystems and the interface from the DAAC subsystems to the Rod Drive Motor-Generator Set Trip Devices, is determined by a TADOT (SR 3.3.6.6). These TADOTs overlap with the ACTUATION LOGIC TEST.

The DHP also provides indications and alarms to support the manual actions credited in the D3 Coping Analysis (Ref. 2), and to monitor and control critical safety functions.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The DAS is required to provide a diverse capability to trip the reactor and actuate the specified safety-related equipment. The DAS is not credited for mitigating accidents in the Chapter 15 safety analyses. The DAS satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

The DAS LCO provides the requirements for the OPERABILITY of the DAS necessary to place the reactor in a shutdown condition and to remove decay heat in the event that required PSMS components do not function due to CCF.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

A DAS measurement channel consists of the measurement device, its interface to each of the four DAAC subsystems, and the associated bistable within each of the four DAAC subsystems. A DAS measurement channel is OPERABLE provided the "as-found" values of the calibration settings checked during CHANNEL CALIBRATION do not exceed their associated Allowable Values, and the "as-found" value of the analog bistable trip setpoint checked during COT does not exceed its associated Allowable Value. Failure of any instrument renders the affected channel inoperable and reduces the reliability of the affected Functions.

Due to redundant components within the DAS, such as analog bistables, voting logic, time delays and power supplies, an inoperable component may or may not result in an inoperable channel/subsystem. Where an inoperable component results in an inoperable required channel/subsystem, LCOs are entered. For inoperable components that do not result in inoperable channels/subsystems, LCOs are not entered.

The DAS is required to be OPERABLE in the MODES specified in Table 3.3.6-1. All functions of the DAS are required to be OPERABLE in MODES 1, 2 and 3 with the Pressurizer Pressure > P-11.

DAS functions are as follows:

1. <u>Reactor Trip, Turbine Trip and Main Feedwater Isolation</u>

   a. <u>Manual Initiation</u>

      The LCO requires one channel to be OPERABLE. The channel consists of the Reactor Trip, Turbine Trip and Main Feedwater Isolation - Manual Initiation switch and its interface to DAAC 1 and 3, and the Permissive Switch for DAS HSI and its interface to DAAC 2 and 4. The Permissive Switch for DAS HSI is common for all DAS Manual Initiation/Control Functions. The operator can initiate a specific DAS Function at any time by operation of both of these switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Actuation Logic and Actuation Outputs

This LCO requires four DAAC subsystems to be OPERABLE. Actuation Logic and Actuation Outputs consists of all circuitry housed within the DAAC, up to the Rod Drive Motor-Generator Set Trip Devices or the Power Interface modules for the ESF equipment.

c. Low Pressurizer Pressure

There are four Low Pressurizer Pressure channels with two-out-of-four voting logic in each DAAC subsystem. This automatic function is automatically blocked when status signals (P-4) are received indicating that the minimum combination of the RTBs have actuated for the RT function. The LCO requires 3 Low Pressurizer Pressure channels for each DAAC subsystem to be OPERABLE.

d. High Pressurizer Pressure

There are four High Pressurizer Pressure channels with two-out-of-four voting logic in each DAAC subsystem. This automatic function is automatically blocked when status signals (P-4) are received indicating that the minimum combination (2-out-of-4) of the RTBs have actuated for the RT function. The LCO requires 3 High Pressurizer Pressure channels for each DAAC subsystem to be OPERABLE.

e. Low Steam Generator Water Level

There is one Low SG Water Level channel for each SG (four total). The LCO requires 1 Low SG Water Level channel for each DAAC subsystem to be OPERABLE on any 3 Steam Generators. These signals from each SG are processed with two-out-of-four voting logic in each DAAC subsystem. The D3 Coping Analysis (Ref. 2) demonstrates that the two-out-of-four voting logic is adequate for all secondary events including loss of feedwater and SG rupture. This automatic function is automatically blocked when status signals (P-4) are received indicating that the minimum combination (2-out-of-4) of the RTBs have actuated for the RT function.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

f. Rod Drive Motor-Generator Set Trip Device

This LCO requires two Rod Drive Motor-Generator Set Trip Device subsystems, one for each Motor-Generator set, to be OPERABLE. This is because each subsystem trips one Motor-Generator set and both Motor-Generator sets must be tripped for this Reactor Trip Function. The DAS cannot initiate a Reactor Trip with a failure of a Rod Drive Motor-Generator Set Trip Device.

2. Emergency Feedwater Actuation

a. Manual Initiation

Manual Initiation consists of the same features and operates in the same manner as described for DAS Function 1.a. One channel is required to be OPERABLE.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

c. Low Steam Generator Water Level

The Low Steam Generator Water Level channels consist of the same features and operate in the same manner as described for DAS Function 1.e. One Low SG Water Level channel for each DAAC subsystem is required to be OPERABLE on any 3 Steam Generators.

The DAS Emergency Feedwater (EFW) Actuation automatic function is automatically blocked when status signals are received indicating that the PSMS ESFAS EFW function has actuated correctly. Correct actuation is indicated when status signals are received from limit switch contacts on the steam inlet valves to the turbine driven EFW pumps or from auxiliary contacts on the motor starters controlling the motor driven EFW pumps.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. ECCS Actuation

a. Manual Initiation

Manual Initiation consists of the same features and operates in the same manner as described for DAS Function 1.a. One channel is required to be OPERABLE.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

c. ECCS Actuation – Low-Low Pressurizer Pressure

There are four Low-Low Pressurizer Pressure channels with two-out-of-four voting logic in each DAAC subsystem. This automatic function is automatically blocked when status signals are received from auxiliary contacts on the motor starters controlling the Safety Injection (SI) pumps, indicating that 2-out-of-4 pumps have actuated. The LCO requires 3 Low-Low Pressurizer Pressure channels for each DAAC subsystem to be OPERABLE.

4. Containment Isolation

a. Manual Initiation

There are two valves for each containment penetration. Only one of the two valves is controlled by the DAS. Manual Initiation consists of the same features and operates in the same manner as described for DAS Function 1.a. One channel is required to be OPERABLE.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. EFW Isolation Valves

a. Manual Control

There are separate EFW Isolation Valves Control channels for each Steam Generator. Manual Control consists of the same features and operates in the same manner as described for DAS Function 1.a. The LCO requires one channel to be OPERABLE for each of the four Steam Generators. The operator can initiate this Function for any single Steam Generator at any time by operation of both of these switches in the control room.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

6. Pressurizer Safety Depressurization Valves

a. Manual Control

There are four Pressurizer Safety Depressurization Valves. Only one of the four valves is controlled by the DAS. The LCO requires one channel to be OPERABLE. The channel consists of the Pressurizer Safety Depressurization Valves - Manual Control switch, and the Permissive Switch for DAS HSI. The Permissive Switch for DAS HSI is common for all DAS Manual Initiation /Control Functions. The operator can initiate this function at any time by operation of both of these switches in the control room.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Main Steam Depressurization Valves

a. Manual Control

There are separate Main Steam Depressurization Valve Control channels for each Steam Generator. The LCO requires one channel to be OPERABLE for each of the four Steam Generators. A channel consists of the Main Steam Depressurization Valves - Manual Control switch, and the Permissive Switch for DAS HSI. The Permissive Switch for DAS HSI is common for all DAS Manual Initiation/Control Functions. The operator can initiate this Function for any single Steam Generator at any time by operation of both of these switches in the control room.

8. Main Steam Line Isolation

a. Manual Initiation

Manual Initiation consists of the same features and operates in the same manner as described for DAS Function 1.a. One channel is required to be OPERABLE.

b. Actuation Logic and Actuation Outputs

Actuation Logic and Actuation Outputs consist of the same features and operate in the same manner as described for DAS Function 1.b. Four subsystems are required to be OPERABLE.

ACTIONS

In all cases where the LCO states “Restore channel or subsystem to OPERABLE status”, this means restore the required number of channels or subsystems to OPERABLE status. Therefore, restoration of an alternate channel or subsystem, other than the failed channel or subsystem, is also acceptable.

A.1

Condition A applies when one or more subsystems or required channels are inoperable in one or more Functions. With one subsystem or required channel inoperable, 30 days are allowed to restore the channel or subsystem to OPERABLE status.

BASES

ACTIONS (continued)

The Completion Time of 30 days is justified because the DAS is a separate and diverse non-safety backup system. In addition, the Completion Time considers that the remaining OPERABLE channels and Actuation Logic and Actuation Outputs subsystems are adequate to perform the DAS Function.

The Required Actions are modified by two Notes. Note 1 allows placing the Actuation Logic of one subsystem or one required channel in bypass for up to 4 hours while performing surveillance testing, provided the Actuation Logic in the other subsystems or the other required channels are OPERABLE. This Note does not allow a bypass with one channel or subsystem in the tripped condition, as for the RTS and ESFAS, to avoid a spurious DAS actuation.

The Bypass Time of 4 hours for Actuation Logic and channels is justified because the remaining OPERABLE channels or subsystems are adequate to perform the safety function.

Note 2 allows placing the Actuation Outputs of two subsystems in bypass for up to 4 hours while performing surveillance testing of the Actuation Outputs from the other subsystems, or surveillance testing of the Rod Drive Motor-Generator Set Trip Devices. This bypass avoids spurious DAS actuation, because the Actuation Outputs and Rod Drive Motor-Generator Set Trip Devices must be actuated for these tests and they do not have bypass test capability.

When the Actuation Outputs of DAAC 1 or DAAC 3 are tested, this Note allows bypassing the Actuation Outputs of DAAC 2 and DAAC 4, to prevent spurious signals that would result in a spurious reactor trip or ESF actuation. When the Actuation Outputs of DAAC 2 or DAAC 4 are tested, this Note allows bypassing the Actuation Outputs of DAAC 1 and DAAC 3, to prevent spurious signals that would result in a spurious reactor trip or ESF actuation.

When Rod Drive Motor-Generator Set Trip Device 1 is tested, this Note allows bypassing the Actuation Outputs of DAAC 2 and DAAC 4, to prevent spurious signals that would trip Rod Drive Motor-Generator Set Trip Device 2 and cause a spurious reactor trip. When Rod Drive Motor-Generator Set Trip Device 2 is tested, this Note allows bypassing the Actuation Outputs of DAAC 1 and DAAC 3, to prevent spurious signals that would trip Rod Drive Motor-Generator Set Trip Device 1 and cause a spurious reactor trip.

ACTIONS (continued)

The Bypass Time of 4 hours for Actuation Outputs is justified because the DAS is a separate and diverse non-safety backup system.

The 4 hour Bypass Time for all Functions is reasonable, based on operating experience that 4 hours is the average time required to perform a channel, Actuation Logic, Actuation Output or Rod Drive Motor-Generator Set Trip Device surveillance.

B.1 and B.2

Condition B applies when the Required Action and associated Completion Time of Condition A are not met. In this condition, 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 6 hours and to MODE 4 within 12 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 3.3.6.1

SR 3.3.6.1 is performance of CHANNEL CHECK. Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

[The Surveillance Frequency of 31 days is justified based on the following: Since sensor signals used by the DAS are distributed from the PSMS, the CHANNEL CHECK of the DAS sensors is included in the PSMS CHANNEL CHECK, which is conducted automatically and continuously. The isolation module of the PSMS and the indicator of the DAS, that cannot be confirmed by the continuous CHANNEL CHECK on the PSMS, are manually confirmed by this SR. These conventional analog devices, which operate only in mild environments, have a long history of proven reliability.

OR the Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2

A COT is performed on each required channel to ensure the DAAC process control equipment (including analog bistable modules) and DHP indications and alarms will perform their intended Function. The COT for DAS is performed by injecting simulated process measurement signals at a point that overlaps with the CHANNEL CALIBRATION. The signal distribution module for sensors shared between PSMS and DAS shall be checked by either CHANNEL CALIBRATION or COT.

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

The COT confirms the accuracy of the channel’s trip setting (i.e., the channel’s analog bistable state change). The state change must occur within the Allowable Value of the Nominal Trip Setpoint. The Nominal Trip Setpoints and Allowable Values are recorded and maintained in a document established by the SCP.

The analog setpoint shall be left set consistent with the Calibration Tolerance recorded and maintained in a document established by the SCP.

[The Surveillance Frequency of 24 months is adequate. It is based on industry operating experience with Anticipated Transient Without Scram (ATWS) mitigation systems.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test must be performed consistent with the methods and assumptions of Specification 5.5.21, SCP, to verify that the channel responds to a measured parameter within the necessary range and accuracy. Since all DAS channels are shared with the PSMS, a Note has been added that allows the CHANNEL CALIBRATION conducted for the PSMS in LCO 3.3.1 or 3.3.2 to be credited for DAS.

[The Surveillance Frequency of 24 months is based on the assumption of 24 months calibration interval in the determination of the magnitude of equipment drift in accordance with Specification 5.5.21, Setpoint Control Program (SCP).

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.6.4

An ACTUATION LOGIC TEST is performed on each of the four Diverse Automatic Actuation Cabinet subsystems. All possible logic combinations are tested for each protection function. Verification of each Logic module, and Output module is included in this test.

[The Surveillance Frequency of 24 months is adequate. It is based on industry operating experience with Anticipated Transient Without Scram (ATWS) mitigation systems.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.5

A TADOT is performed for the Manual Initiation/Control and Actuation Outputs of all DAS functions. This test actuates the outputs to the PSMS Power Interface modules. Through overlap with the ACTUATION LOGIC TEST, the TADOT confirms these outputs can be generated from the Manual Initiation/Control switches and from the automatic actuation logic.

[The Surveillance Frequency of 24 months is adequate, based on industry operating experience with ATWS mitigation systems, considering instrument reliability and operating history data of solid state Actuation Outputs devices.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.3.6.6

A TADOT for the Rod Drive Motor-Generator set trip devices is performed by actuating the Manual Initiation switch from the control room and by verifying actuation of the Rod Drive Motor-Generator set trip device. Through overlap with the ACTUATION LOGIC TEST, the TADOT confirms the Rod Drive Motor-Generator set trip devices can be actuated from the Manual Initiation/Control switches and from the automatic actuation logic.

[The Surveillance Frequency of 24 months is based on known reliability of the Function, and has been shown to be acceptable through operating experience with ATWS mitigation systems.

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. MUAP-07006-P-A, Revision 2, “Defense-in-Depth and Diversity.”

2. MUAP-07014-P, Revision 5, “Defense-in-Depth and Diversity Coping Analysis.”

3. FSAR Section 7.8.

4. 10 CFR 50.49.

5. 10 CFR 50.36.

6. FSAR Chapter 15.

7. MUAP-09022-P, Revision 3, “US-APWR Instrument Setpoint Methodology.”

8. U.S. Nuclear Regulatory Commission, Standard Review Plan, Branch Technical Position 7-19, “Guidance for Evaluation of Diversity and Defense-in-Depth in Digital Computer-Based Instrumentation and Control Systems.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state operational envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

BASES

APPLICABLE SAFETY ANALYSES (continued)

The pressurizer pressure limit and RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, usually based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

RCS total flow rate contains a measurement error based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators.

The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have been adjusted for instrument error.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

BASES

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Periodic Surveillance for pressurizer pressure is performed to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. [The 12 hour Surveillance Frequency is sufficient since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation is within safety analysis assumptions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.2

Periodic Surveillance for RCS average temperature is performed to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. [The 12 hour Surveillance Frequency is sufficient since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.1.3

Surveillance for RCS total flow rate is performed using the installed flow instrumentation. [The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

[The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

BASES

REFERENCES 1. Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES (continued)

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical (k_{eff} ≥ 1.0) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with k_{eff} ≥ 1.0, LCO 3.4.2 is applicable since the reactor can only be critical (k_{eff} ≥ 1.0) in these MODES.

The special test exception of LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with K_{eff} < 1.0 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with K_{eff} < 1.0 in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 551°F. [The SR to verify RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

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

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. Reference 1 mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 5).

BASES

BACKGROUND (continued)

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

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

The criticality limit curve includes the Reference 1 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 7 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing and criticality; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

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

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

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

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile (brittle) failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, they are applicable at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," LCO 3.4.2, "RCS Minimum Temperature for Criticality," and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure.

BASES

APPLICABILITY (continued)

Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. Restoration of P/T parameters to the analyzed range reduces the RCPB stress.

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS (continued)

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

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

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

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

BASES

ACTIONS (continued)

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. [This Frequency of 30 minutes is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

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

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

BASES

REFERENCES (continued)

3. ASTM E 185-82, July 1982.

4. 10 CFR 50, Appendix H.

5. Regulatory Guide 1.99, Revision 2, May 1988.

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. Subsection 5.3.2.1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission,

b. Improving the neutron economy by acting as a reflector,

c. Carrying the soluble neutron poison, boric acid,

d. Providing a second barrier against fission product release to the environment, and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing a SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant

BASES

APPLICABLE SAFETY ANALYSES (continued)

safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump, broken shaft, or coastdown, and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 120% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 118% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.5,	"RCS Loops - MODE 3,"
LCO 3.4.6,	"RCS Loops - MODE 4,"
LCO 3.4.7,	"RCS Loops - MODE 5, Loops Filled,"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled,"
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.6,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. [The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops - MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

APPLICABLE SAFETY ANALYSES (continued)

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

When the Rod Control System is not capable of rod withdrawal, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure that safety analyses limits are met.

The Note permits all RCPs to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow.

The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

LCO (continued)

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2,"
LCO 3.4.6,	"RCS Loops - MODE 4,"
LCO 3.4.7,	"RCS Loops - MODE 5, Loops Filled,"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled,"
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.6,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration for Required Action A.1 is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If one required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal (e.g., de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal. The Completion Times of 1 hour, to restore the required RCS loop to operation or defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

BASES

ACTIONS (continued)

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

If two required RCS loops are inoperable or a required RCS loop is not in operation, except as during conditions permitted by the Note in the LCO section, the Rod Control System must be placed in a condition incapable of rod withdrawal (e.g., all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets). All operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. [The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 14% for required RCS loops. If the SG secondary side narrow range water level is < 14%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. [The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.5.3

Verification that each required RCP is OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to each required RCP. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the containment spray/residual heat removal (CS/RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or two RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that additional paths be available to provide redundancy for decay heat removal.

Additionally, forced coolant circulation provided by at least one RCP ensures that the concentration of soluble boron in the reactor coolant is homogeneous. However, when no RCPs are operating, all isolation valves for reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be secured closed to prevent unplanned boron dilution of the reactor coolant. This will ensure that an inadvertent boron dilution event does not occur under reduced flow conditions where unborated water could stratify in the RCS.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each RHR loop required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The prevention of an accidental boron dilution event is ensured by requiring that all sources of unborated water be isolated from the RCS when RCS circulation is not provided by at least one operating RCP..

RCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops or three RHR loops are OPERABLE in MODE 4 and that one of the RCS loops or two of the RHR loops are in operation. Any one RCS loop or two RHR loops in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Additionally, this LCO requires that all sources of unborated water be isolated from the RCS to prevent an inadvertent boron dilution event in MODE 4 with no running RCPs (Reference 1). However, planned dilution and makeup operations are sometimes required during MODE 4 with no RCPs running to compensate for transient conditions which result in a continuous change in the RCS mass (see discussion of Note 3 below).

Note 1 permits all RCPs or CS/RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 3 permits the opening of isolation valves for unborated water sources for when in a planned and procedurally controlled dilution or makeup activity provided that this activity is not prohibited by Note 1. Planned dilution and makeup operations are sometimes required to compensate for transient conditions which result in a continuous change in the RCS mass. Procedures should minimize to the extent practicable the time unborated water sources are not isolated during the conduct of these operations. Once such an operation is complete the exception no longer applies and action to close the valves must be initiated immediately. It is expected that any unborated water isolation valve used in the planned activity will be secured in the closed position within 15 minutes following the planned activity.

BASES

LCO (continued)

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE CS/RHR pump capable of providing forced flow to an OPERABLE CS/RHR heat exchanger. RCPs and CS/RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RCS or two loops of RHR provides sufficient circulation for the removal of decay heat from the core. However, two loops of RHR do not provide sufficient circulation to provide proper boron mixing. Therefore, the LCO requires that the valves used to isolate unborated water sources be secured in the closed position when no RCPs are running. Additional loops consisting of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2,"
LCO 3.4.5, "RCS Loops - MODE 3,"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled,"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled,"
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6), and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

If one required loop is inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

A.2

If restoration is not accomplished and two RHR loops are OPERABLE, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only two RHR loops OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 rather than MODE 4. The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

This Required Action is modified by a Note which indicates that the unit must be placed in MODE 5 only if two RHR loops are OPERABLE. With no RHR loop OPERABLE, the unit is in a condition with only limited cooldown capabilities. Therefore, the actions are to be concentrated on the restoration of a RHR loop, rather than a cooldown of extended duration.

ACTIONS (continued)

B.1 and B.2

If two or more required loops are inoperable or a required loop(s) are not in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until the required loop(s) are restored to OPERABLE status and operation.

C.1

ACTION C has two Notes. The first Note allows separate Condition entry for each unborated water source isolation valve. The second Note requires that Required Action C.2 be completed whenever Condition C is entered.

Preventing inadvertent dilution of the reactor coolant boron concentration when there is insufficient RCS mixing is dependent on maintaining the unborated water isolation valves secured closed when there are no RCPs operating. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of immediately requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position in a timely manner. Once actions are initiated, they must be continued until the valves are secured in the closed position.

BASES

ACTIONS (continued)

C.2

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.1.1.1 (verification of boron concentration) must be performed whenever Condition C is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that the required RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. In the event that no RCPs are operating to provide sufficient mixing conditions to satisfv the Chapter 15 Safety Analysis assumption the operator is instructed to perform SR 3.4.6.4 to isolate all sources of unborated water to prevent an inadvertent dilution. [The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 14%. If the SG secondary side narrow range water level is < 14%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. [The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.3

Verification that each required pump is OPERABLE ensures that an additional RCS or CS/RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

SR 3.4.6.4

Verification that unborated water sources are isolated from the RCS when operating with RHR loops in service and no RCPs running ensures that an inadvertent boron dilution cannot occur under plant conditions that do not provide adequate boron mixing. [The Frequency of 7 days is reasonable considering the location of some of the valves and the fact that once secured closed the valves cannot be inadvertently repositioned. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that state that the SR is not required to be performed if any RCP is in operation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.5

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation the the RHR system is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that states the SR is not required to be performed until 12 hours after entering MODE 4. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering MODE 4.

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

REFERENCES	1.	Subsection 15.4.6

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the containment spray/residual heat removal (CS/RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation (Ref. 1) are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of four RHR loops connected to the RCS, each loop containing a CS/RHR heat exchanger, a CS/RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least two RHR loops for decay heat removal and transport. The flow provided by two RHR loops is adequate for decay heat removal. The other intent of this LCO is to require that a third path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first two paths can be RHR loops that must be OPERABLE and in operation. The third path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels ≥ 14% to provide an alternate method for decay heat removal via natural circulation (Ref. 1).

The CS/RHR pumps do not provide sufficient circulation of water through the RCS to ensure that the concentration of soluble boron in the reactor coolant is homogeneous. Therefore, all isolation valves for reactor makeup water sources containing unborated water that are connected to the RCS must be secured closed to prevent unplanned boron dilution of the reactor coolant.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to

BASES

BACKGROUND (continued)

perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each RHR loop required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The prevention of an accidental boron dilution event is ensured by requiring that all sources of unborated water be isolated from the RCS when RCS circulation is only provided by the CS/RHR pumps.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ 14%. Two RHR loops provide sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 14%. Should one of the operating RHR loops fail, the SGs could be used to remove the decay heat via natural circulation.

Additionally, this LCO requires that all sources of unborated water be isolated from the RCS to prevent an inadvertent boron dilution event in MODE 5. However, planned dilution and makeup operations are sometimes required during MODE 5 to compensate for transient conditions which result in a continuous change in the RCS mass (see discussion of Note 5 below).

Note 1 permits all CS/RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test

LCO (continued)

and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other two required RHR loops are OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

LCO (continued)

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops. The requirement for isolation of the unborated water sources is removed as soon as one RCP is in operation.

Note 5 permits the opening of isolation valves for unborated water sources for when in a planned and procedurally controlled dilution or makeup activity provided that this activity is not prohibited by Note 1. Planned dilution and makeup operations are sometimes required to compensate for transient conditions which result in a continuous change in the RCS mass. Procedures should minimize to the extent practicable the time unborated water sources are not isolated during the conduct of these operations. Once such an operation is complete the exception no longer applies and action to close the valves must be initiated immediately. It is expected that any unborated water isolation valve used in the planned activity will be secured in the closed position within 15 minutes following the planned activity.

CS/RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core. Two loops of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ 14%. Two loops of RHR do not provide sufficient circulation to provide proper boron mixing. Therefore, the LCO requires that the valves used to isolate unborated water sources be secured in the closed position when no RCPs are running.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2;"
LCO 3.4.5,	"RCS Loops - MODE 3;"
LCO 3.4.6,	"RCS Loops - MODE 4;"
LCO 3.4.8,	"RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation -High Water Level" (MODE 6)," and
LCO 3.9.6,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6)."

ACTIONS

A.1 and A.2

If two RHR loops are OPERABLE and in operation and either the required SGs have secondary side water levels < 14%, or one required RHR loop is inoperable, redundancy for heat removal is lost. Action must be initiated immediately to restore a third RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If less than two RHR loops are in operation, except during conditions permitted by Note 1, or if less than two loops are OPERABLE, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore two RHR loops to OPERABLE status and operation must be initiated. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

C.1

ACTION C has two Notes. The first Note allows separate Condition entry for each unborated water source isolation valve. The second Note requires that Required Action C.2 be completed whenever Condition C is entered.

Preventing inadvertent dilution of the reactor coolant boron concentration when there is insufficient RCS mixing is dependent on maintaining the unborated water isolation valves secured closed when there are no RCPs operating. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of immediately requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position in a timely manner. Once actions are initiated, they must be continued until the valves are secured in the closed position.

BASES

ACTIONS (continued)

C.2

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.1.1.1 (verification of boron concentration) must be performed whenever Condition C is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. [The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ≥ 14% ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If two RHR loops are OPERABLE, this Surveillance is not needed. [The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that each required CS/RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required CS/RHR pump. Alternatively, verification that a pump is in operation also verifies proper breaker alignment and power availability. If secondary side water level is ≥ 14% in at least two SGs, this Surveillance is not needed. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

SR 3.4.7.4

Verification that unborated water sources are isolated from the RCS when operating with RHR loops in service and no RCPs running ensures that an inadvertent boron dilution cannot occur under plant conditions that do not provide adequate boron mixing. [The Frequency of 7 days is reasonable considering the location of some of the valves and the fact that once secured closed the valves cannot be inadvertently repositioned. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that state that the SR is not required to be performed if any RCP is in operation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.5

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds an acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the containment spray/residual heat removal (CS/RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with the RCS loops not filled, only CS/RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least two CS/RHR pumps for decay heat removal and transport and to require that three paths be available to provide redundancy for heat removal.

The CS/RHR pumps do not provide sufficient circulation of water through the RCS to ensure that the concentration of soluble boron in the reactor coolant is homogeneous. Therefore, all isolation valves for reactor makeup water sources containing unborated water that are connected to the RCS must be secured closed to prevent unplanned boron dilution of the reactor coolant.

In MODE 5 with the RCS loops not filled, low-pressure letdown line isolation valves are automatically closed upon detection of RCS loop lowlevel signal to prevent loss of RCS inventory. The function is effective to prevent core damage during plant shutdown, based on probabilistic risk assessment.

In Mode 5 with the RCS not filled, one additional source of injection water (beyond a CS/RHR pump) will reduce the calculated core damage frequency. One safety injection (SI) pump can provide this injection source. A water source is also required.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each RHR loop required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

BASES

APPLICABLE SAFETY ANALYSES	In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The flow provided by two RHR loops is adequate for heat removal. The prevention of an accidental boron dilution event is ensured by requiring that all sources of unborated water be isolated from the RCS when RCS circulation is not provided by at least one operating RCP. RCS loops in MODE 5 (loops not filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii). The need for one SI pump is based on the PRA insight that maintaining at least one RCS injection function operable results in a reduction in core damage risk during shutdown conditions (Mode 5) with the RCS partially filled.
LCO	The purpose of this LCO is to require that at least three RHR loops be OPERABLE and two of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of two running CS/RHR pumps meets the LCO requirement for two loops in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations. Additionally, this LCO requires that all sources of unborated water be isolated from the RCS to prevent an inadvertent boron dilution event in MODE 5. However, planned dilution and makeup operations are sometimes required during MODE 5 to compensate for transient conditions which result in a continuous change in the RCS mass (see discussion of Note 3 below). The LCO requires the low-pressure letdown line isolation valves to be OPERABLE to mitigate the effects associated with loss of RCS inventory. The LCO also requires that one SI pump be OPERABLE such that in response to a manual operator start the pump can provide sufficient water to mitigate a drain-down event while in Mode 5 with the RCS partially filled. The LCO requires that a source of water (i.e., reactor water storage pit (RWSP) and water available from the refueling cavity) be available and contain the necessary volume of water. The capability to provide injection water is important to achieve defense-in-depth during Mode 5 with the RCS partially filled. The ability of the pump to provide flow to the RCS while partially filled (and at near atmospheric pressure) and have electrical power are the criteria necessary to be OPERABLE in Mode 5. No pump automatic start features are required to be OPERABLE in Mode 5 as these capabilities were not credited in the PRA.

BASES

LCO (continued)

Note 1 permits one CS/RHR pump to be removed from operation for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping one CS/RHR pump is to be limited to situations when the outage time is short and core outlet temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure SDM of LCO 3.1.1 is maintained or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other two required loops are OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

Note 3 permits the opening of isolation valves for unborated water sources for when in a planned and procedurally controlled dilution or makeup activity provided that this activity is not prohibited by Note 1. Planned dilution and makeup operations are sometimes required to compensate for transient conditions which result in a continuous change in the RCS mass. Procedures should minimize to the extent practicable the time unborated water sources are not isolated during the conduct of these operations. Once such an operation is complete the exception no longer applies and action to close the valves must be initiated immediately. It is expected that any unborated water isolation valve used in the planned activity will be secured in the closed position within 15 minutes following the planned activity.

An OPERABLE RHR loop is comprised of an OPERABLE CS/RHR pump capable of providing forced flow to an OPERABLE CS/RHR heat exchanger. CS/RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System. However, the RHR system does not provide sufficient RCS circulation to ensure proper boron mixing. Therefore, the LCO requires that the valves used to isolate unborated water sources be secured in the closed position.

Operation in other MODES is covered by:

LCO 3.4.4,	"RCS Loops - MODES 1 and 2,"
LCO 3.4.5,	"RCS Loops - MODE 3,"
LCO 3.4.6,	"RCS Loops - MODE 4,"
LCO 3.4.7,	"RCS Loops - MODE 5, Loops Filled,"
LCO 3.9.5,	"Residual Heat Removal (RHR) and Coolant Circulation - High Water Level (MODE 6)," and
LCO 3.9.6,	"Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level (MODE 6)."

BASES

ACTIONS

A.1

If one required RHR loop is inoperable, redundancy for RHR is lost. Action must be initiated to restore a third loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of three paths for heat removal.

B.1

If one low-pressure letdown isolation valve is inoperable, the automatic isolation function to prevent loss of RCS inventory is lost. Action must be initiated to restore the valve to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of three paths for heat removal.

C.1 and C.2

If less than two required loops are OPERABLE or less than two required loops in operation, except during conditions permitted by Note 1, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore two RHR loops to OPERABLE status and operation. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until two loops are restored to OPERABLE status and operation.

ACTIONS (continued)

D.1

ACTION D has two Notes. The first Note allows separate Condition entry for each unborated water source isolation valve. The second Note requires that Required Action D.2 be completed whenever Condition D is entered.

Preventing inadvertent dilution of the reactor coolant boron concentration when there is insufficient RCS mixing is dependent on maintaining the unborated water isolation valves secured closed when there are no RCPs operating. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of immediately requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position in a timely manner. Once actions are initiated, they must be continued until the valves are secured in the closed position.

D.2

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.1.1.1 (verification of boron concentration) must be performed whenever Condition C is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

BASES

ACTIONS (continued)

E.1, E.2, E.3, E.4

In the event that no SI pump is available to inject water into the RCS, the RWSP does not contain sufficient water volume (SR 3.4.8.6), or boron concentration is not within limits (SR 3.4.8.7) to mitigate a RCS drain-down event in Mode 5 while the RCS is partially filled, then actions must be initiated immediately to restore this capability. The PRA indicates that the availability of an injection water source reduces the core damage frequency. Additionally, until such capability is restored, any activity that could result in lowering RCS water volume must be suspended. The immediate COMPLETION TIME reflects the importance of maintaining water injection capability while the RCS is in a partially filled condition.

F.1, F.2, F.3.1 and F.3.2

If no RHR loop is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with [four] bolts,

b. One door in each air lock must be closed, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

With RHR loop requirements not met, the potential exists during an RCS drain down event for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions stated above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded. The Completion Time of 4 hours allows fixing of most CS/RHR pumps problems and is reasonable, based on the availability of the standby RHR loop and one SI train for injection water, and on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. [The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.8.2

Verification that each required CS/RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to each required pump. Alternatively, verification that a CS/RHR pump is in operation also verifies proper breaker alignment and power availability. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that states the SR is not required to be performed until 24 hours after a required pump is not in operation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.3

SR 3.4.8.3 requires a complete cycle of each low-pressure letdown isolation valve. This requirements mean confirmation of OPERABILITY of Instrumentation and its control (Setpoints, Channel Checks, Channel Calibrations) and valve. Operating a low-pressure letdown isolation valve through one complete cycle ensures that the low-pressure letdown isolation valve can be automatically actuated to mitigate the effects from loss of RCS inventory. [The Frequency of 24 months is based on engineering judgment, taking into consideration the conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations into account based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.8.4

Verification that unborated water sources are isolated from the RCS when operating with RHR loops in service and no RCPs running ensures that an inadvertent boron dilution cannot occur under plant conditions that do not provide adequate boron mixing. [The Freguency of 7 days is reasonable considering the location of some of the valves and the fact that once secured closed the valves cannot be inadvertently repositioned. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note that state that the SR is not required to be performed if any RCP is in operation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.5

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds an acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

SURVEILLANCE REQUIREMENTS (continued)

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

SR 3.4.8.6

Verification that the RWSP contains a borated water volume (including water available in the refueling cavity) ≥ 79,920 ft^3 (597,800 gallons) ensures that the pump will have a sufficient inventory of water to mitigate the Mode 5 RCS drain-down event assumed in the probabilistic risk assessment (PRA). [Since the RWSP volume (including the water available in the refueling cavity) is normally stable, is protected by an alarm, and in view of other administrative controls available, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.8.7

The boron concentration of the RWSP should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a RCS drain down event. [Since the RWSP volume (including the water available in the refueling cavity) is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.8

Verification that the breaker alignment is correct and indicated power is available to the required SI pump ensures that the pump motor will be available to drive the pump upon manual start. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.8.9

Periodic surveillance testing of an SI pump to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant PRA for a drain-down event in Mode 5 with a partially filled RCS. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls and emergency power supplies. Pressurizer safety valves and safety depressurization valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Safety Depressurization Valves (SDVs)," respectively.

The intent of the LCO is to ensure that a liquid-vapor interface exists in the pressurizer to permit effective RCS pressure control during normal operation and assure the pressurizer continues to provide proper pressure control response for Anticipated Operational Occurrences (AOOs). The presence of an adequate steam volume is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control. The maximum water level defined by the LCO preserves the steam space necessary for pressure control, prevents overfilling the pressurizer, and ensures that two-phase or water relief does not lead to a more severe accident in accordance with the requirements of SRP 15.0 (Ref. 2). Note that the LCO is not intended to be interpreted as an operating band. The actual operating band for pressurizer water level is controlled more tightly than this LCO and is defined by the deviation alarms associated with the programmed level which is a function of power.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is

BASES

BACKGROUND (continued)

important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for an adequate steam volume is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam volume and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure (Ref. 1).

The maximum pressurizer water level limit, which ensures that a steam volume exists in the pressurizer and prevents two-phase or water relief and pressurizer overfill, satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

Some Chapter 15 AOOs result in an increase in RCS temperature and resultant increase in pressurizer level. For many of these events, the decrease in reactor power following reactor trip effectively terminates this increase in RCS temperature and leads to a stabilization or decrease in pressurizer level. Therefore, such events are protected from pressurizer overfill and water or two-phase relief by the high pressurizer water level reactor trip, specified in Table 3.3.1-1 of TS 3.3.1 and Table 7.2-3 of Section 7.2 of Chapter 7. This is also true for all Chapter 15 AOOs that begin from MODES 2 and 3 because the potential heatup of the core is limited by the low (≤ 5%) or zero power in those MODES.

However, certain Chapter 15 AOOs beginning from MODE 1, such as the loss of non-emergency AC power to the station auxiliaries (Ref. 3) and the loss of normal feedwater flow (Ref. 4), result in a continued increase in pressurizer water level even after reactor trip, mainly due to the presence of decay heat and reduced secondary heat sink capability. In these events, the

APPLICABLE SAFETY ANALYSES (continued)

initial steam volume needs to be sufficient to accommodate the increase in pressurizer water level without leading to overfill and two-phase or water relief. The basis for the pressurizer water level LCO value in MODE 1 is that the safety analysis of these limiting Chapter 15 AOO have sufficient margin to pressurizer overfill and two-phase or water relief when initiated from the LCO value.

LCO

The LCO requirement in MODE 1 for the pressurizer to be OPERABLE with a water volume ≤ 1757 cubic feet, which is equivalent to 60%, ensures that a sufficient steam volume exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam volume is also consistent with analytical assumptions. This LCO requirement further ensures that the limiting AOO that results in an increase in pressurizer level that cannot be terminated by prior operator action will not result in pressurizer overfill and water or two phase relief even if the event initiates from the LCO. The limiting AOOs for this LCO is the loss of non-emergency AC power to the station auxiliaries (Ref. 3) and loss of normal feedwater flow (Ref. 4).

The LCO requirement in MODES 2 and 3 for the pressurizer to be OPERABLE with a water volume ≤ 2600 cubic feet, which is equivalent to 92%, is provided for the same reasons as in MODE 1. However, the LCO value is higher due to the reduced risk of pressurizer overfill or water or two-phase relief since the initial power level is low (≤ 5%).

Note that these LCO requirements are not intended to define the operating band of the pressurizer water level. The operating band is controlled more tightly than these LCO requirements and is defined by the deviation alarms associated with the programmed level which is a function of power.

The LCO requires three groups of OPERABLE pressurizer heaters, each with a capacity ≥ 120 kW, capable of being powered from either the offsite power source or the emergency power supply. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The exact design value of 120 kW is derived from the use of three heaters rated at 46.8 kW each. The amount needed to maintain pressure is dependent on the heat losses.

BASES

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODE 1. MODE 1 is the condition that provides minimum margin to pressurizer overfill and two-phase or water relief for AOOs that result in a net integrated pressurizer insurge. MODE 2 is applicable for the same reasons, although the LCO value is increased due to the lower initial power level of ≤ 5%. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1, A.2, A.3, and A.4

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3 with all rods fully inserted and incapable of withdrawal. Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

BASES

ACTIONS (continued)

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 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

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below 60% for MODE 1 and 92% for MODES 2 and 3. The Surveillance is performed by observing the indicated level. [The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumption of ensuring that a sufficient steam volume exists in the pressurizer. Alarms are also available for early detection of abnormal level indications. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. [The Frequency of 24 months is considered adequate to detect heater degradation and 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 15.0.0.2.2.

2. Standard Review Plan (SRP) Section 15.0 “Introduction – Transient and Accident Analyses”.

3. Subsection 15.2.6

4. Subsection 15.2.7

5. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2733.5 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The capacity for each valve, 432,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with one or more RCS cold leg temperatures ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES

APPLICABLE SAFETY ANALYSES

All accident and safety analyses that require safety valve actuation assume operation of four pressurizer safety valves to limit increases in RCS pressure. Accidents that could result in overpressurization if not properly terminated include:

a. Loss of external electrical load,

b. Loss of normal feedwater flow,

c. Reactor coolant pump shaft break,

d. Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low-power startup condition,

e. Spectrum of rod cluster control assembly ejection accidents, and

f. Feedwater line break

Detailed analyses of the above transients are contained in Chapter 15 (Ref. 2). Safety valve actuation is required in events a, b, and d (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions (Ref. 2 and 3).

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The four pressurizer safety valves are set to open at the RCS design pressure 2485 psig, and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of four valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

APPLICABILITY (continued)

The LCO is not applicable in MODE 4 when any RCS cold leg temperatures are ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 72 hour exception is based on 18 hour outage time for each of the four valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe. The 72 hour exception has a small impact in view of risk insights.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperatures ≤ Low Temperature Overpressure Protection (LTOP) arming temperature specified in the PTLR within 24 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. With any RCS cold leg temperatures at or below Low Temperature Overpressure (LTOP) arming temperature specified in the PTLR, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by four pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 1% for OPERABILITY; and the valves are reset to remain within ± 1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III, NB 7500.

2. Chapter 15.

3. Subsection 5.2.2.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Safety Depressurization Valves (SDVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and SDVs. The SDVs are motor operated valves that are manually operated to open following an accident in order to decrease RCS pressure. The SDVs are manually operated from the main control room.

Block valves, which are normally open, are located between the pressurizer and the SDVs. The block valves are used to isolate the SDVs in case of excessive leakage or a stuck open SDV. Block valve closure is accomplished manually using controls in the main control room. A stuck open SDV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The SDVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the SDVs and their block valves permit performance of surveillances on the valves during power operation.

The SDVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis.

The SDVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. Two SDVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two SDVs, each having a relief capacity of 530,000 lb/hr at 2335 psig.

BASES

APPLICABLE SAFETY ANALYSES	For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The SDVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator. Pressurizer SDVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requires the SDVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR and to depressurize RCS associated with safety shutdown. By maintaining two SDVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized with the capability to be closed, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. The block valves may be OPERABLE when closed to isolate the flow path of an inoperable SDV that is capable of being manually cycled (e.g., as in the case of excessive SDV leakage). Similarly, isolation of an OPERABLE SDV does not render that SDV or block valve inoperable provided the relief function remains available with manual action. An OPERABLE SDV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage. Satisfying the LCO helps minimize challenges to fission product barriers.

BASES

APPLICABILITY

The SDVs are required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event and to depressurize the RCS during safety shutdown.

The LCO is not applicable in MODES 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant.

ACTIONS

Note 1 has been added to clarify that all pressurizer SDVs and block valves are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

SDVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the SDVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the SDVs to eliminate the problem condition.

Quick access to the SDV for pressure control can be made when power remains on the closed block valve and furthermore pressurizer safety valve can be expected to open at its set pressure. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

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

If one SDV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the SDVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one SDV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable SDV to OPERABLE status. If the SDV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

[Required Action B.3.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

ACTIONS (continued)

C.1 [and C.2]

If one block valve is inoperable, then it is necessary to restore the block valve to OPERABLE status within the Completion Time of 72 hours. Because at least one SDV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable SDV in Condition B, since the SDVs may not be capable of mitigating an event if the inoperable block valve is not full open. If it cannot be restored within the completion time of 72 hours, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D. [Required Action C.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

The Required Action C.1 is modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable SDV (which require the block valve power to be removed once it is closed) are adequate to address the condition.

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then 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.

E.1, E.2, E.3, and E.4

If more than one SDV is inoperable, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no SDVs are restored within the Completion Time, then 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.

ACTIONS (continued)

F.1

If more than one block valve is inoperable, it is necessary to restore at least one block valves within 2 hours. The Completion Time is reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, then 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

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. [The basis for the Frequency of 92 days is the ASME Code (Ref. 2). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note stating that it is not required to be performed with the block valve closed in accordance with the Required Actions of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each SDV. Operating a SDV through one complete cycle ensures that the SDV can be manually actuated for mitigation of an SGTR. [The Frequency of 24 months 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES

1. Regulatory Guide 1.32, Rev. 3, March 2004.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

RCS pressure is limited by the LTOP System at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable RHR suction valve line relief valve setpoint and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all but two safety injection pumps and one charging pump incapable of injection into the RCS and isolating the accumulators. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. Two RHR suction relief valves or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the ECCS actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core

BASES

BACKGROUND (continued)

decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than two SI pumps or one charging pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two residual heat removal (RHR) suction relief valves. Two RHR suction relief valves have adequate relieving capability to keep from overpressurization for the required coolant input capability.

RHR Suction Relief Valve Requirements

During LTOP MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot legs to the inlets of the CS/RHR pumps. While these valves are open, the RHR suction relief valves are exposed to the RCS and are able to relieve pressure transients in the RCS.

The RHR suction relief valves are spring loaded, water relief valves with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it may require removing a pressurizer safety valve, removing a SDV, or opening a SDV and disabling its block valve in the open position. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, and in MODE 4 with RCS cold leg temperature exceeding LTOP arming temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. When the RHR system is placed in service, overpressure prevention is provided by two RHR suction relief valves or by a depressurized RCS and a sufficient sized RCS vent.

The actual temperature at which the pressure in the P/T limit curve falls below the RHR suction relief valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RHR suction relief valve or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Inadvertent actuation of pressurizer heaters,

b. Loss of RHR cooling, or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Rendering all but two safety injection pumps and one charging pump incapable of injection,

b. Deactivating the accumulator discharge isolation valves in their closed positions, and

APPLICABLE SAFETY ANALYSES (continued)

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," provide this protection.

The Reference 4 analyses demonstrate that either two RHR suction relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when two safety injection pumps and one charging pump are actuated. Thus, the LCO allows only two safety injection pumps and one charging pump OPERABLE during the LTOP MODES.

Since neither two RHR suction relief valves nor the RCS vent can handle the pressure transient need from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions. The analyses show the effect of accumulator discharge is over a narrower RCS temperature range (195°F and below) than that of the LCO (LTOP arming temperature and below).

Fracture mechanics analyses established the temperature of LTOP Applicability at LTOP arming temperature specified in the PTLR.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 6 and 7), requirements by having a maximum of two SI pumps and one charging pump OPERABLE and SI actuation enabled.

<u>RHR Suction Relief Valve Performance</u>

The RHR suction relief valves do not have variable pressure and temperature lift setpoints. Analyses must show that two RHR suction relief valves lifting at its specified setpoint will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the P/T limit curve. Assuming all relief flow requirements during the limiting LTOP event, two RHR suction relief valves will maintain RCS pressure to within the valve rated lift setpoint, plus an accumulation ≤ 10% of the rated lift setpoint.

APPLICABLE SAFETY ANALYSES (continued)

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 4.7 square inches is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow possible from either the mass or heat input transient, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The required vent area may be created by removing SDVs with their associate block valves secured in the open position or by removal of pressurizer safety valves.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

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

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

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that a maximum of two safety injection pumps and one charging pump be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The LCO is modified by two Notes. Note 1 allows two charging pumps to be made capable of injecting for ≤ 1 hour during pump swap operations. One hour provides sufficient time to safely complete the actual transfer and to complete the administrative controls and Surveillance Requirements associated with the swap. The intent is to minimize the actual time that more than one charging pump is physically capable of injection. Note 2 states that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

BASES

LCO (continued)

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

a. Two OPERABLE RHR suction relief valves, or

An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valve and its RHR suction valve are open, its setpoint is within limits, and testing has proven its ability to open at this setpoint.

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 4.7 square inches.

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

APPLICABILITY

This LCO is applicable in MODE 4 when any RCS cold leg temperature is ≤ LTOP arming temperature specified in the PTLR, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above LTOP arming temperature specified in the PTLR. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 when RHR is isolated or RCS temperature is above LTOP arming temperature specified in the PTLR.

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

ACTIONS

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

ACTIONS (continued)

A.1 and B.1

With three or more safety injection pumps, or two or more charging pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

C.1, D.1, and D.2

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1 and Required Action D.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to >LTOP arming temperature specified in the PTLR, an accumulator pressure of 695 psig cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

E.1 and E.2

With the RCS pressurized and an RHR suction relief valve inoperable, there is a potential to overpressurize the RCS and exceed the limits allowed in LCO 3.4.3. The RHR suction relief valve is considered inoperable if one or both of the RHR suction isolation valves are closed such that the RHR suction relief valve in that RHR train cannot perform its intended safety function, or if the valve itself will not operate to perform its intended safety function.

Under these conditions, Required Action E.1 or E.2 provides two options, either of which must be accomplished in 12 hours. If the RHR suction relief valve cannot be restored to OPERABLE status, the RCS must be depressurized and vented with an RCS vent which provides a flow area sufficient to mitigate any of the design low temperature overpressure events.

ACTIONS (continued)

The 12 hour completion time represents a reasonable time to repair the relief valve, open the RHR isolation valves or otherwise restore the system to OPERABLE status, or depressurize and vent the RCS, without imposing a lengthy period when the LTOP system is not able to mitigate a low temperature overpressure event.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of two safety injection pumps and a maximum of one charging pump are verified incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out.

The safety injection pumps and charging pump are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed.

[The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.12.4

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying both RHR suction isolation valves are open. This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO.

The RHR suction isolation valves are verified to be opened. [The Frequency of 12 hours is considered adequate in view of other administrative controls such as valve status indications available to the operator in the control room that verify the RHR suction valve remains open. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.5

The RCS vent of ≥ 4.7 square inches is proven OPERABLE by verifying its open condition [either:

a. Once every 12 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context) or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position). A removed pressurizer safety valve or open manway also fits this category. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The passive vent path arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12b.

SR 3.4.12.6

The RHR suction relief valves shall be demonstrated OPERABLE by verifying that both RHR suction isolation valves in one flow path are open and by testing them in accordance with the Inservice Testing Program. (Refer to SR 3.4.12.4 for the RHR suction isolation valve Surveillance.) This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO. The ASME Code (Ref. 5), test per Inservice Testing Program verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

SR 3.4.12.7

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying its RHR suction valve and RHR suction isolation valve are open. This Surveillance is only performed if the RHR suction relief valve is being used to satisfy this LCO.

The RHR suction isolation valve is verified locked open, with power to the valve operator removed, to ensure that accidental closure will not occur. The “locked open” valve must be locally verified in its open position with the manual actuator locked in its inactive position. [The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve position. OR The Surveillance Frequency is based on operating

BASES

SURVEILLANCE REQUIREMENTS (continued)

experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix G.

2. Generic Letter 88-11.

3. ASME, Boiler and Pressure Vessel Code, Section III.

4. Subsection 5.2.2.

5. ASME, Code for Operation and Maintenance of Nuclear Power Plants.

6. 10 CFR 50, Section 50.46.

7. 10 CFR 50, Appendix K.

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 make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and 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.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 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 that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment 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 reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

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 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 that primary to secondary LEAKAGE from all steam generators (SGs) is 600 gallons per day. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is equivalent to the conditions assumed in the safety analysis (Ref. 3).

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

LCO

RCS 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

0.5 gallon per minute (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 detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (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 SG

BASES

LCO (continued)

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

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.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 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 primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

BASES

ACTIONS (continued)

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. 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 at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions (stable temperature, power level, pressurizer, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return 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. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

SURVEILLANCE REQUIREMENTS (continued)

[The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. The 150 gallons per day limit is measured at room temperature as described in Reference 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

[The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45 Revision 1, May 2008.
3. Chapter 15.
4. NEI 97-06, "Steam Generator Program Guidelines."
5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for containment spray.

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System,

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BACKGROUND (continued)

b. Safety Injection System, and

c. Chemical and Volume Control System.

The PIVs are listed in Chapter 3. (Ref. 6).

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 900 psig, and 900 psig design is able to bear the RCS pressure without pipe rupture, overpressurization failure of the RHR low pressure line is prevented, thus preventing a LOCA outside containment and subsequent risk of core melt.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

BASES

LCO (continued)

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period.

ACTIONS (continued)

B.1 and B.2

If leakage cannot be reduced, the system cannot be isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

The inoperability of the RHR suction valve interlock renders the RHR suction isolation valves incapable of preventing inadvertent opening of the valves at RCS pressures in excess of the RHR systems design pressure. If the RHR suction valve interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This Action accomplishes the purpose of the suction valve interlock function.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 24 months, but may be extended if the plant does not go into MODE 5 for at least 7 days. [The 24month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code (Ref. 7), and 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

Testing must also be performed once, to ensure tight reseating after an RCS PIV has been actuated. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

SURVEILLANCE REQUIREMENTS (continued)

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months. In addition, this Surveillance is not required to

be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

SR 3.4.14.2

Verifying that the RHR suction valve interlock is OPERABLE ensures that RCS pressure will not pressurize the RHR system beyond its design pressure of 900 psig. The interlock setpoint is set so the actual RCS pressure must be < 425 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded and the RHR relief valves will not lift. [The 24 month Frequency is based on the need to perform the Surveillance under conditions that apply during a plant outage. The 24 month Frequency is also acceptable 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. From the instrumentation aspects, the Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. 10 CFR 50, Appendix A, Section V, GDC 55.

4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

5. NUREG-0677, May 1980.

6. Subsection 3.9.6.3.4.

7. ASME Code for Operation and Maintenance of Nuclear Power Plants.

8. 10 CFR 50.55a(g).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE and air cooler condensate flow rate monitor are instrumented to alarm for increases of greater than or equal to 0.5 gpm in the normal flow rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivity of 10^{-9} μCi/cc radioactivity for particulate monitoring is practical for these leakage detection system. Radioactivity detection system is included for monitoring particulate activity because of their sensitivity and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

BASES

BACKGROUND (continued)

BACKGROUND

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from air coolers. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

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

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the Chapter 5 (Ref. 3). Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

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

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

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

LCO (continued)

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor and a containment air cooler condensate flow rate monitor, provides an acceptable minimum.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

BASES

ACTIONS (continued)

B.1.1, B.1.2, B.2.1, and B.2.2

With particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors. Alternatively, continued operation is allowed if the air cooler condensate flow rate monitoring system is OPERABLE, provided grab samples are taken or water inventory balances performed every 24 hours.

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1 and C.2

With the required containment air cooler condensate flow rate monitor inoperable, alternative action is again required. Either SR 3.4.15.1 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of the containment air cooler condensate flow rate monitor to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS LEAKAGE. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

BASES

ACTIONS (continued)

D1 and D.2

With the required containment atmosphere radioactivity monitor and the required containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the containment sump monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

E.1 and E.2

If a Required Action of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. [The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The test verifies the alarm setpoint and relative accuracy of the instrument string. [The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.4.15.3, SR 3.4.15.4, and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. [The Frequency of 24 months 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. From the instrumentation aspects, the Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.

2. Regulatory Guide 1.45 Revision 1, May 2008.

3. Chapter 5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at low population zone outer boundary for the radiological release duration, is specified in 10 CFR 50. 34 (Ref. 1). Doses to control room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the dose consequences in the event of a steam system piping failure or a steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2).

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting offsite and control room doses meet the appropriate SRP acceptance criteria following a steam system piping failure or a SGTR accident. The safety analyses (Ref. 3 and 4) assume the specific activity of the reactor coolant is at the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 600 gpd exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.14, "Secondary Specific Activity."

The analyses for the steam system piping failure and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

APPLICABLE SAFETY ANALYSES (continued)

The safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a steam system piping failure (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 60 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or an RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 300 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal. If the reactor trip system has not automatically tripped the reactor, operators are assumed to manually trip the reactor.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the main steam relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) system is placed in service.

The steam system piping failure radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor trip occurs after the generation of an SI signal on low steam line pressure. The affected SG blows down completely and steam is vented directly to the atmosphere. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR system is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 60.0 μCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

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

BASES

LCO	The iodine specific activity in the reactor coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 300 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet the appropriate SRP acceptance criteria (Ref. 2). The steam system piping failure and SGTR accident analyses (Refs. 3 and 4) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a steam system piping failure or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 2).
APPLICABILITY	In MODES 1, 2, 3 and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a steam system piping failure or SGTR to within the SRP acceptance criteria (Ref. 2). In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is ≤ 60 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is continued every 4 hours to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limit within 48 hours. The Completion Time of 48 hours is acceptable since it is expected that, if there were an iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a steam system piping failure or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

B.1

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within limit within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a steam system piping failure or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Action and the associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 is > 60 μCi/gm , the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Time are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant [at least once every 7 days OR according to the Surveillance Frequency Control Program]. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in the noble gas specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. [The 7 day Frequency considers the low probability of a gross fuel failure during this time. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes with similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in the SR 3.4.16.1 calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT Xe-133 is not detected, it should be assumed to be present at the minimum detectable activity.

A Note modifies the SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

SR 3.4.16.2

This Surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. [The 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The Frequency,

BASES

SURVEILLANCE REQUIREMENTS (continued)

between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

The Notes modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

REFERENCES

1. 10 CFR 50.34.

2. Standard Review Plan (SRP) Section 15.0.3 " Design Basis Accident Radiological Consequences of Analyses for Advanced Light Water Reactors."

3. Subsection 15.1.5.

4. Subsection 15.6.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system’s pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops – MODES 1 and 2," LCO 3.4.5, "RCS Loops – MODE 3," LCO 3.4.6, "RCS Loops – MODE 4," and LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is only briefly released to the atmosphere via safety valves and relief valves.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 600 gallons per day (gpd). For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 50.34 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

LCO (continued)

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 150 gpd per SG, except for specific types of degradation at specific locations where the NRC has approved greater accident induced leakage. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

LCO (continued)

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1 and A.2</u>

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity

ACTIONS (continued)

determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

SURVEILLANCE REQUIREMENTS (continued)

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

<u>SR 3.4.17.2</u>

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.9 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. 10 CFR 50 Appendix A, GDC 19.

3. 10 CFR 50.34.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 RCS Loops - Test Exceptions

BASES

BACKGROUND	The primary purpose of this test exception is to provide an exception to LCO 3.4.4, "RCS Loops - MODES 1 and 2," to permit reactor criticality under no flow conditions during certain PHYSICS TESTS (natural circulation demonstration, station blackout, and loss of offsite power) to be performed while at low THERMAL POWER levels. Section XI of 10 CFR 50, Appendix B (Ref. 1), 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 the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the power plant as specified in GDC 1, "Quality Standards and Records" (Ref. 2). The key objectives of a test program are to provide assurance that the facility has been adequately designed to validate the analytical models used in the design and analysis, to verify the assumptions used to predict plant response, to provide assurance that installation of equipment at the unit has been accomplished in accordance with the design, and to verify that the operating and emergency procedures are adequate. Testing is performed prior to initial criticality, during startup, and following low power operations. The tests will include verifying the ability to establish and maintain natural circulation following a plant trip at low power, performing decay heat removal via natural circulation, and during the natural circulation condition, showing that pressure can be controlled using auxiliary spray and pressurizer heaters powered from the emergency power sources.
APPLICABLE SAFETY ANALYSES	The tests described above require operating the plant without forced convection flow and as such are not bounded by any safety analyses. However, operating experience has demonstrated this exception to be safe under the present applicability. As describe in LCO 3.0.7, compliance with Test Exception LCOs is optional, and therefore no criteria of 10 CFR 50.36(c)(2)(ii) apply. 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.

BASES

LCO

This LCO provides an exemption to the requirements of LCO 3.4.4.

The LCO is provided to allow for the performance of PHYSICS TESTS in MODE 2 (after a refueling), where the core cooling requirements are significantly different than after the core has been operating. Without the LCO, plant operations would be held bound to the normal operating LCOs for reactor coolant loops and circulation (MODES 1 and 2), and the appropriate tests could not be performed.

In MODE 2, where core power level is considerably lower and the associated PHYSICS TESTS must be performed, operation is allowed under no flow conditions provided THERMAL POWER is ≤ P-7 and the reactor trip setpoints of the OPERABLE power level channels are set ≤ 25% RTP. This ensures, if some problem caused the plant to enter MODE 1 and start increasing plant power, the Reactor Trip System (RTS) would automatically shut it down before power became too high, and thereby prevent violation of fuel design limits.

The exemption is allowed even though there are no bounding safety analyses. However, these tests are performed under close supervision during the test program and provide valuable information on the plant's capability to cool down without offsite power available to the reactor coolant pumps.

APPLICAIBILITY

This LCO is applicable when performing low power PHYSICS TESTS without any forced convection flow. This testing is performed to establish that heat input from nuclear heat does not exceed the natural circulation heat removal capabilities. Therefore, no safety or fuel design limits will be violated as a result of the associated tests.

ACTIONS

A.1

When THERMAL POWER is ≥ the P-7 interlock setpoint 10%, the only acceptable action is to ensure the reactor trip breakers (RTBs) are opened immediately in accordance with Required Action A.1 to prevent operation of the fuel beyond its design limits. Opening the RTBs will shut down the reactor and prevent operation of the fuel outside of its design limits.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

Verification that the power level is < the P-7 interlock setpoint (10%) will ensure that the fuel design criteria are not violated during the performance of the PHYSICS TESTS. The Frequency of once per hour is adequate to ensure that the power level does not exceed the limit. Plant operations are conducted slowly during the performance of PHYSICS TESTS and monitoring the power level once per hour is sufficient to ensure that the power level does not exceed the limit.

SR 3.4.18.2

The power range and intermediate range neutron detectors. P-10, and the P-13 interlock setpoint must be verified to be OPERABLE and adjusted to the proper value. The Low Power Reactor Trips Block, P-7 interlock, is actuated from either the Power Range Neutron Flux, P-10, or the Turbine Inlet Pressure, P-13 interlock. The P-7 interlock is a logic Function with train, not channel identity. A COT is performed prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS. The SR 3.3.1.7 Frequency is sufficient for the power range and intermediate range neutron detectors to ensure that the instrumentation is OPERABLE before initiating PHYSICS TESTS, because the RTS is self-tested on a continuous basis from digital side of all input modules to the digital side of all output modules.

SR 3.4.18.3

The Low Power Reactor Trips Block, P-7 interlock, must be verified to be OPERABLE in MODE 1 by LCO 3.3.1, “Reactor Trip System Instrumentation.” The P-7 interlock is actuated from either the Power Range Neutron Flux, P-10, or the Turbine Inlet Pressure, P-13 interlock. The P-7 interlock is a logic Function. An ACTUATION LOGIC TEST is performed to verify OPERABILITY of the P-7 interlock prior to initiation of startup and PHYSICS TESTS. This will ensure that the RTS is properly functioning to provide the required degree of core protection during the performance of the PHYSICS TESTS

.BASES

REFERENCES
1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50, Appendix A, GDC 1, 1988.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase and well into the core reflooding phase of a loss of coolant accident (LOCA). They provide inventory to accomplish the refill phase that follows the LOCA, and start reflooding the reactor. They also provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The large flow of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with small flow from the accumulator and the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

BASES

BACKGROUND (continued)

The B-10 isotopic concentration of the reactor coolant in the RCS is depleted very slowly with reactor operation due to the neutron flux in the core. When the boron recycle subsystem is used, the reactor coolant containing depleted B-10 is recycled and returned to the RCS. After being recycled numerous times, the isotopic concentration of B-10 in the boric acid solution being returned to the RCS gradually decreases. During refueling outages, the reactor coolant in the RCS is mixed with the refueling water stored in the RWSP. With the repeated mixing of each cycle, the isotopic concentration of B-10 of the refueling water in the RWSP can gradually decrease over a long period of time. Since the RWSP water may be used to add water inventory to the accumulators, the isotopic B-10 concentration in the accumulators may also gradually decrease over a long period of time. The depleted B-10 of the boric acid solution in the accumulators can be recovered by increasing the overall boron concentration or the B-10 isotopic concentration itself. The requirement to verify the B-10 isotopic concentration is only required if the boron recycle subsystem is used.

APPLICABLE SAFETY ANALYSIS

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Refs. 1 and 3). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the SI pumps cannot deliver flow until the Class 1E gas turbine generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for SI pump flow until an effective delay has elapsed. This delay accounts for the Class 1E gas turbine generators starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and safety injection pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the safety injection pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F,

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation,

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react, and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase and core reflooding phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

The safety analysis assumes values of 19,338 gallons and 19,734 gallons.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is 3434 gallons larger than the deliverable volume for the accumulators, since the flow damper is near the bottom of the accumulators and the dead volume in each accumulator is 3434 gallons. For small breaks, an increase in water volume is a peak clad temperature penalty. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The safety analysis treats the volume of water from the accumulator to the RCS isolation check valves as accumulator injection line.

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The safety analysis assumes that the boron has the isotopic concentration of B-10 found in natural boron (10.9 atom percent). The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH. The upper limit of boron concentration is not related to reactivity and is not dependent on the B-10 isotopic concentration.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 1 and 3).

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

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1920 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the SI pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1 [and A.2]

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break for the majority of plants. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

B.1 [and B.2]

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is reasonable based on the consideration that the conclusion of TSTF-370 is applicable to US-APWR. The basic design concept of US-APWR including the design base success criteria of accumulators, and the core damage scenarios after postulated LOCA events when an accumulator is inoperable are equivalent with conventional PWRs, and therefore, the TSTF-370 is considered applicable. Additionally, PRA studies in Chapter 19, Subsection 19.1.4.1.2 (Ref. 4) show low CDF increment under conditions where one accumulator is inoperable. [Required Action B.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

BASES

ACTIONS (continued)

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and RCS pressure reduced to ≤ 1000 psig 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.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. [The Frequency of 12 hours is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.5.1.2 and SR 3.5.1.3

Borated water volume and nitrogen cover pressure are verified for each accumulator. [The Frequency of 12 hours is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator since the static design of the accumulators limits the ways in which the concentration can be changed. [The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] Sampling the affected accumulator within 6 hours after a 1% volume increase will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage Pit (RWSP), because the water contained in the RWSP is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

SR 3.5.1.5

Verification that power is removed from each accumulator isolation valve operator when the RCS pressure is ≥ 1920 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. [Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is < 1920 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.6

Periodic verification [every 24 months OR according to the Surveillance Frequency Control Program] that the isotopic concentration of B-10 in each accumulator is ≥ 19.9% (atom percent) ensures that the B-10 isotopic concentration assumed in the accident analysis is available. [Since B-10 in the accumulators is not directly exposed to a significant neutron flux and the reactor coolant and RWSP water used as inventory for the accumulators is only mixed with the reactor coolant during outages, 24 months is considered conservative. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 6.2.1.
2. 10 CFR 50.46.
3. Subsection 15.6.5.
4. Subsection 19.1.4.1.2.
5. NUREG-1366, February 1990.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 Safety Injection System (SIS) - Operating

BASES

BACKGROUND

The function of the SIS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system,

b. Rod ejection accident,

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater, and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are two phases of SIS operation: direct vessel injection (DVI) and hot leg recirculation. In the DVI phase, water is taken from the refueling water storage Pit (RWSP) and injected directly into the reactor vessel downcomer. After approximately 4 hours of DVI, the SIS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The SIS consists of four 50% capacity trains. The ECCS accumulators and the RWSP are also part of the ECCS, but are not considered part of an SIS flow path as described by this LCO.

The SIS flow paths consist of piping, valves, and pumps such that water from the RWSP can be injected into the RCS following the accidents described in this LCO. The major component of each train is the SI pump. Each pump is capable of supplying 50% of the flow required to mitigate the accident consequences. Four 50% capacity SIS trains ensure 100% of the required flow is delivered to the reactor with one train out of service, while still meeting the single failure criterion.

BASES

BACKGROUND (continued)

The Safeguards Component Area HVAC System is a support system that provides temperature control for the SI Pump Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each SIS train required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

The four SIS trains are located in the four quadrants surrounding the Containment Vessel. A dedicated line from the RWSP penetrates through the Containment Vessel in each quadrant to the suction of the SI pump train located in the Reactor Building and associated with that quadrant. Each SI pump discharges through a direct injection throttle valve to a DVI nozzle on the reactor vessel. Each SIS train flow path is completely independent of the other three trains.

During low temperature conditions in the RCS, limitations are placed on the maximum number of SI pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The SI pumps are actuated upon receipt of an ECCS actuation signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the Class 1E gas turbine generators (GTGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with Class 1E GTG starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active SIS components, along with the passive accumulators and the RWSP covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Pit (RWSP)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F,

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation,

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react,

d. Core is maintained in a coolable geometry, and

e. Adequate long term core cooling capability is maintained.

APPLICABLE SAFETY ANALYSES (continued)

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

The SIS is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the SI pumps, as well as the maximum response time for their actuation. The SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the SI pumps. The SGTR and MSLB events also credit the SI pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one SI pump while another SI pump is assumed out of service, i.e., 2 SI pumps are assumed to operate (two Class 1E GTG trains are assumed to operate due to requirements for modeling full active containment heat removal system operation) and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one SIS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the reactor vessel downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that at least two SIS trains are available to deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

Long term core cooling is achieved by using the SI pumps.

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

LCO

In MODES 1, 2, and 3, three independent (and redundant) SIS trains are required to ensure that sufficient SIS flow is available, assuming a single failure affecting one of the three required trains. Additionally, individual components within the SIS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an SIS train consists of the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWSP upon an ECCS actuation signal.

During an event requiring ECCS actuation, a flow path is required to

provide an abundant supply of water from the RWSP to the RCS via the SI pumps and their respective supply headers to each of the four direct vessel injection nozzles. In the long term, this flow path may be switched to supply its flow between the RCS hot and cold legs. Management of gas voids is important to ECCS OPERABILITY.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable the capability of two or more SIS trains.

As indicated in Note 1, the SIS flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room.

As indicated in Note 2, operation in MODE 3 with SIS trains made incapable of injecting in order to facilitate entry into or exit from the Applicability of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that certain pumps be rendered incapable of injecting at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to make pumps incapable of injecting prior to entering the LTOP Applicability, and provide time to restore the inoperable pumps to OPERABLE status on exiting the LTOP Applicability.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the ECCS actuation signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "SIS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring SIS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1 [and A.2]

With one required train inoperable and at least 100% of the SIS flow equivalent to a two OPERABLE SIS train available, one inoperable train must be returned to OPERABLE status within 72 hours. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine the Risk Informed Completion Time (RICT).] The 72 hour Completion Time refers is based on PRA analyses described in Chapter 19 (Ref. 5) and is a reasonable time for repair of many SIS components.

An SIS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

Chapter 19 (Ref. 5) has shown that the impact of having one required SIS train inoperable is sufficiently small to justify continued operation for 72 hours.

ACTIONS (continued)

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and 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

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the SI pumps to the RCS is maintained. Misalignment of these valves could render two SIS trains inoperable. Securing these valves in position by removal of power ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. [A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.5.2.2

Verifying the correct alignment for manual and power operated valves in the SIS flow paths provides assurance that the proper flow paths will exist for SIS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. [The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path and restore the system to a condition equivalent to the design condition if directed.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3

Periodic surveillance testing of SI pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.4

This Surveillance demonstrates that each ECCS valve manually activated during a design basis accident event actuates to the required position. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in required position. SRs are specified in the Inservice activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5

This Surveillance demonstrates that each SI pump starts on receipt of an actual or simulated ECCS actuation signal. [The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.6

Periodic inspections of the ECC/CS STRAINER ensure that it is unrestricted and stays in proper operating condition. [The 24 month Frequency 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds an acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the ECCS is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. Subsection 6.2.1.
4. Subsection 15.6.5.
5. Chapter 19.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 Safety Injection System (SIS) - Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "Safety Injection System (SIS) - Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the SIS train requirement is two trains.

An SIS flow path consists of piping, valves, and an SI pump such that water from the refueling water storage pit (RWSP) can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the SIS operational requirements are reduced. It is understood in these reductions that certain automatic ECCS actuation is not available. In this MODE, sufficient time exists for manual actuation of the required SIS to mitigate the consequences of a DBA.

Only two trains of SIS are required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The SIS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODE 4, two of the four independent (and redundant) SIS trains are required to be OPERABLE to ensure that sufficient SIS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWSP.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWSP to the RCS via the SI pumps to the reactor vessel direct injection nozzles associated with the SIS train. Management of gas voids is important to ECCS OPERABILITY.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for SIS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, two OPERABLE SIS trains are acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring SIS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

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

A.1

With one of the two required SIS trains inoperable, the plant is not capable of providing SIS flow at 100% capacity for Design Basis Events requiring safety injection. The 1 hour Completion Time to restore required SIS train to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where no SIS trains are required.

B.1

When the Required Actions of Condition A cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.5.3.1 The applicable Surveillance descriptions from Bases 3.5.2 apply.
REFERENCES	The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Pit (RWSP)

BASES

BACKGROUND

The RWSP supplies borated water to the Safety Injection System (SIS) and the Containment Spray (CS) System during accident conditions.

The RWSP supplies four trains of the SIS and four trains of the CS System through separate, redundant supply headers. A motor operated isolation valve is provided in each header to allow isolation of the RWSP from its associated SIS or CS train if required for maintenance. Use of a single RWSP to supply all four trains of the SI system and CS System is acceptable since the RWSP is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

Design ensures that during a design basis event, the RWSP is replenished with water which has been released to the containment from the RCS sufficient to maintain adequate net positive suction head to the SI and containment spray/ residual heat removal (CS/RHR) pumps throughout the event.

During normal operation in MODES 1, 2, and 3, the SI and CS/RHR pumps are aligned to take suction from the RWSP.

The SIS and CS system pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

This LCO ensures that:

a. Sufficient borated water volume exists to support continued operation of the SI and CS/RHR pumps and

b. The reactor remains subcritical following a LOCA.

Insufficient water in the RWSP could result in insufficient suction head for the SI and CS/RHR pumps. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

The B-10 isotopic concentration of the reactor coolant in the RCS is depleted very slowly with reactor operation due to the neutron flux in the core. When the boron recycle subsystem is used, the reactor coolant containing depleted B-10 is recycled and returned to the RCS. After being recycled numerous times, the isotopic concentration of B-10 in the boric acid solution being returned to the RCS gradually decreases. During refueling outages, the

BACKGROUND (continued)

reactor coolant in the RCS is mixed with the refueling water stored in the RWSP. With the repeated mixing of each cycle, the isotopic concentration of B-10 of the refueling water in the RWSP can gradually decrease over a long period of time. The depleted B-10 of the boric acid solution in the RWSP can be recovered by increasing the overall boron concentration or the B-10 isotopic concentration itself. The requirement to verify the B-10 isotopic concentration is only required if the boron recycle subsystem is used.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWSP provides a source of borated water to the SI and CS System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Refs. 1 and 2). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "Safety Injection System (SIS) - Operating," B 3.5.3, " Safety Injection System (SIS) - Shutdown," and B 3.6.6, "Containment Spray Systems." These analyses are used to assess changes to the RWSP in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWSP must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWSP, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration of 4000 ppm is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The safety analysis assumes that the boron has the isotopic concentration of B-10 found in natural boron (19.9 atom percent).

The maximum temperature is an assumption in the steam generator tube rupture analysis; the minimum is an assumption in the MSLB.

For a large break LOCA analysis, the minimum recirculation water volume limit of 43,000 ft^3 (321,700 gallons) and the lower boron concentration limit of 4000 ppm (at the natural B-10 isotopic concentration) are used to compute the post LOCA boron concentration necessary to assure subcriticality. To secure this minimum water volume in the accident, RWSP needs to store boric acid water ≥ 79,920 ft^3 (597,800 gallons) during normal operation. This water volume also bounds the ECCS and CSS pump NPSH Requirements. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The upper limit on boron concentration of 4200 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from direct vessel injection to hot leg injection is to avoid boron precipitation in the core following the accident. The upper limit of boron concentration is not related to reactivity and is not dependent on the B-10 isotopic concentration.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWSP lower temperature limit of 32°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The upper temperature limit of 120°F is used in the small break LOCA analysis and containment OPERABILITY analysis. Exceeding this temperature will result in a higher peak clad temperature, because there is less heat transfer from the core to the injected water for the small break LOCA and higher containment pressures due to reduced containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWSP water temperature are used to maximize the total energy release to containment.

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

LCO

The RWSP ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level to support SIS and CS/RHR pump operation.

To be considered OPERABLE, the RWSP must meet the water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWSP OPERABILITY requirements are dictated by the SIS and Containment Spray System OPERABILITY requirements. Since both the SIS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWSP must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1 [and A.2]

With RWSP boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the SIS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWSP temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time. This Required Action is not applicable in MODE 4.]

ACTIONS (continued)

B.1

With the RWSP inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the SIS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWSP is not required. The short time limit of 1 hour to restore the RWSP to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWSP cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWSP borated water temperature should be verified to be within the limits assumed in the accident analyses band. [The Frequency of 24 hours is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when containment air temperatures are within the operating limits of the RWSP. With containment air temperatures within the band, the RWSP temperature should not exceed the limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

The RWSP water volume should be verified to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued SI pump and CS/RHR pump operation on recirculation. [Since the RWSP volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.5.4.3

The boron concentration of the RWSP should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting RWSP pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. [Since the RWSP volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.5.4.4

Periodic verification that the isotopic concentration of B-10 in the RWSP is ≥ 19.9% (atom percent) ensures that the B-10 isotopic concentration assumed in the accident analysis is available. [Since B-10 in the RWSP is not directly exposed to a significant neutron flux and the RWSP water is only mixed with the reactor coolant during outages, 24 months is considered conservative. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 6.2.2.

2. Subsection 15.6.5.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 pH Adjustment

BASES

BACKGROUND

The Emergency Cooling System (ECCS) includes twenty three NaTB pH adjustment baskets which provide adjustment of the pH of the water in the containment following an accident.

Following an accident with a large release of radioactivity, the containment pH is automatically adjusted to greater than or equal to 7.0, to enhance iodine retention in the containment water. Chemical addition is necessary to counter the affects of the boric acid contained in the safety injection supplies and acids produced in the post-LOCA environment (nitric acid from the irradiation of water and air and hydrochloric acid from irradiation and pyrolysis of electric cable insulation). The desired pH values significantly reduce formation of elemental iodine in the containment water, which reduces the production of organic iodine and the total airborne iodine in the containment. This pH adjustment is also provided to prevent stress corrosion cracking of the ECCS and containment spray system (CSS) components during long-term cooling.

Sodium tetraborate decahydrate (NaTB) contained in baskets provides a passive means of pH control for such accidents. The baskets are made of stainless steel with a mesh that readily permits contact with water. These baskets are located inside three NaTB basket containers at an elevation that is below the lowest spray ring. NaTB in baskets is dissolved in spray water in the containers. The solution containing NaTB is discharged from each container to the RWSP through NaTB solution transfer pipe. Recirculation of water by the safety injection pumps and containment spray / residual heat removal pumps provide mixing to achieve a uniform pH. (Ref. 1)

APPLICABLE SAFETY ANALYSES

In the event of a Design Basis Accident (DBA), iodine may be released from the fuel to containment. To limit this iodine release from containment, the pH of the water in the containment is adjusted by the addition of NaTB. Adjusting the water in containment to neutral or alkaline pH ($pH \geq 7.0$) will augment the retention of the iodine, and thus reduce the iodine available to leak to the environment. (Ref. 1 and 2)

pH adjustment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The requirement to maintain the NaTB baskets with ≥ 44,100 pounds of NaTB assures that for DBA releases of iodine into containment, the pH of the containment water will be adjusted to enhance the retention of the iodine.

APPLICABILITY

In MODES 1, 2, 3, and 4 a DBA could cause release of radioactive iodine to containment requiring pH adjustment. The NaTB baskets assist in reducing the airborne iodine fission product inventory available for release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, pH adjustment is not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

If the NaTB mass in the baskets is not within limits, the iodine retention may be less than that assumed in the accident analysis for the limiting DBA. Due to the very low probability that the mass of NaTB may change, the variations are expected to be minor such that the required capability is substantially available. The 72 hour Completion Time for restoration to within limits is consistent with times applied to minor degradations of ECCS parameters.

B.1 and B.2

If the Required Actions and associated Completion Times 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 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

The minimum mass of NaTB is 44,100 pounds. This mass is based on providing sufficient NaTB to buffer the post accident containment water to a minimum pH of 7.0. Additionally, the NaTB mass is based on treating the maximum volume of post accident water (879,740 gallons) containing the maximum amount of boron (4200 ppm) as well as other sources of acid.

[The periodic verification is required every 24 months, since access to the NaTB pH adjustment baskets is only feasible during outages, and normal fuel cycles are scheduled for 24 months. This Surveillance Frequency is acceptable due to the very low probability that the mass of NaTB may change. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.5.5.2

Testing must be performed to ensure the solubility and buffering ability of the NaTB after exposure to the containment environment. A representative sample of 5.71 grams of NaTB from one of the baskets in containment is submerged in ≥ 1liter of water at a boron concentration of 4200 ppm. At the standard temperature of 120 ± 5°F,without agitation, the solution must be left to stand for 12 hours. The liquid is then decanted and mixed, the temperature is adjusted to 77 ± 2°F. At this point, the pH must be ≥ 7.0.

The minimum required amount of NaTB is sufficient to buffer the maximum amount of boron 4200 ppm, the maximum amount of other acids, and the maximum amount of water 879,740 gallons that can exist in the containment following an accident and achieve a minimum pH of 7.0.

[The periodic verification is required every 24 months, since access to the NaTB pH adjustment baskets is only feasible during outages, and normal fuel cycles are scheduled for 24 months. This Surveillance Frequency is acceptable due to the very low probability that the chemistry of NaTB may change. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Section 6.3.

2. Subsection 15.6.5.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis loss of coolant accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a prestressed, post-tensioned, reinforced concrete structure with a cylindrical wall, hemispherical dome, and a flat, reinforced concrete foundation slab. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The cylinder wall is prestressed with an ungrouted post tensioning system in the vertical and horizontal directions, and the containment dome is prestressed using two way, hoop and inverted U-shape vertical, post tensioning system.

The concrete reactor building is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1).

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

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

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

   2. Closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves,"

BASES

BACKGROUND (continued)

b. Each airlock is OPERABLE, except as provided in LCO 3.6.2, "Containment Airlocks,"

c. All equipment hatches are closed.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting Design Basis Accident (DBA) without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA and steam line break accidents (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBA involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment is designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. In the safety analysis the assumed leakage is 0.15% per day at P_a = 59.5 psig (Ref. 3).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

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

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

BASES

LCO (continued)

Individual leakage rates specified for the containment personnel airlocks (LCO 3.6.2) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program.

Failure to meet personnel airlock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and < 0.75 L_a for overall Type A leakage (Ref. 5). At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis.

SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

For ungrouted, post tensioned tendons, this SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are in accordance with the ASME Code, Section XI, Subsection IWL (Ref. 4), and applicable addenda as required by 10 CFR 50.55a.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. Subsection 15.7.4.

3. Subsection 6.2.1.

4. ASME Code, Section XI, Subsection IWL.

5. NEI94-01.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, approximately 8.5 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock door interlock mechanism is defeated.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (Ref. 2). In the analysis of this accident, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 2). This leakage rate is defined in

BASES

APPLICABLE SAFETY ANALYSES (continued)

10 CFR 50, Appendix J, (Ref. 1), as L_a , the maximum allowable containment leakage rate at the calculated peak containment internal pressure $P_{a,}$ following a design basis LOCA. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the

ACTIONS (continued)

OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

<u>A.1, A.2.1, [A.2.2], and A.3</u>

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed. [Required Action A.2.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time. This Required Action is not applicable in MODE 4.]

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative

ACTIONS (continued)

controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be

verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2.1, [B.2.2], and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

ACTIONS (continued)

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, C.3.1, [and C.3.2]

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock. [Required Action C.3.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time. This Required Action is not applicable in MODE 4.]

D.1 and D.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. [Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the airlock. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. Subsection 6.2.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a ECCS actuation signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a High-3 containment pressure signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the purge and exhaust valves receive an isolation signal on a containment high radiation condition. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

BACKGROUND (continued)

High Volume Purge System (36 inch purge valves)

The High Volume Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. The 36 inch purge valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Low Volume Purge System (8 inch purge valves)

The Low Volume Purge System operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access and

b. Equalize internal and external pressures.

Since the valves used in the Low Volume Purge System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The safety analyses assume that the 36 inch high volume purge valves are closed at event initiation.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The DBA analysis assumes that, within 60seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60seconds includes signal delay, and containment isolation valve stroke times.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch high volume purge valves must be maintained sealed closed. The valves covered by this LCO are listed along with their associated stroke times in Chapter 6 (Ref. 2).

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are those listed in Reference 2.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths , except for 36 inch high volume purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment high volume purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls. A single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.3.1.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event the isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

ACTIONS (continued)

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

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

BASES

ACTIONS (continued)

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

ACTIONS (continued)

C.1.1, [C.1.2,] and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. [Required Action C.1.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time. This Required Action is not applicable in MODE 4.] In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Ref. 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

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

BASES

ACTIONS (continued)

D.1, D.2 and D.3

In the event one or more containment high volume purge valves in one or more penetration flow paths are not within the high volume purge valve leakage limits, purge valve leakage must be restored to within limits, or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, or blind flange. A high volume purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.6. The specified Completion Time is reasonable, considering that one high volume purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the containment high volume purge valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.6 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment high volume purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.6, 184 days, is based on an NRC initiative, Generic Issue B-20 (Ref. 4). Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown to be acceptable based on operating experience.

BASES

ACTIONS (continued)

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

E.1 and E.2

If the Required Actions and associated Completion Times 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 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 36 inch containment high volume purge valve is required to be verified sealed closed. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment high volume purge valve. Detailed analysis conducted for similar plant design of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment high volume purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. [The Frequency of 31 days is a result of an NRC initiative, Generic Issue B-24 (Ref. 5), related to containment purge valve use during plant operations. In the event purge valve leakage requires entry into Condition D, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2

This SR ensures that the low volume purge valves are closed as required or, if open, open for an allowable reason. If a low volume purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the low volume purge valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The low volume purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. [The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. [Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

SURVEILLANCE REQUIREMENTS (continued)

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B, is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. [Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between containment and the environment), a Frequency of 184 days was established as part of the NRC resolution of Generic Issue B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 4). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, decreasing the interval is a prudent measure after a valve has been opened.

SR 3.6.3.7

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance 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 engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 15.6.5.5.

2. Subsection 6.2.4.

3. Standard Review Plan 6.2.4.

4. Generic Issue B-20, “Containment Leakage Due to Seal Deterioration.”

5. Generic Issue B-24.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of transients resulting in negative pressure, such as inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure.

The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case LOCA generates larger mass and energy release than the worst case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 2.0 psig. This resulted in a peak pressure from a LOCA of 57.5 psig. The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure, P_a, results from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA,59.5 psig, does not exceed the containment design pressure, 68 psig.

The containment was also designed for an external pressure load equivalent to -3.9 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure. The initial pressure condition used in this analysis was -0.3 psig. This resulted in a minimum pressure inside containment of -3.9 psig, which is equal to the design load.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. [The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 6.2.1.
2. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND	The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray system during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.
APPLICABLE SAFETY ANALYSES	Containment average air temperature is an initial condition used in the DBA analyses that establish the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1). The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of two ESF buses, which is the worst case single active failure plus maintenance outage, resulting in two trains each of the Containment Spray/Residual Heat Removal System being rendered inoperable.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120 °F. This resulted in a maximum containment air temperature of 281.93°F. The containment design temperature is 300°F based on LOCA analysis.

The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design temperature for only a short time during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the equipment surface temperatures remained below the design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray/Residual Heat Removal System (Ref. 1).

The containment pressure transient is sensitive to the temperature of structures in containment which work as heat sinks during the DBAs and therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a LOCA. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

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

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the containment structural temperature is maintained below its design temperature. Therefore the containment vessel and required safety related equipment within containment will continue to perform their functions.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. [The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment temperature condition. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES	1.	Subsection 6.2.1.
	2.	10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray System

BASES

BACKGROUND

The Containment Spray system provides containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray System is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," and GDC 40, "Testing of Containment Heat Removal Systems," (Ref. 1).

The Containment Spray System is an Engineered Safety Feature (ESF) system. It is designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System limits and maintains post accident conditions to less than the containment design values.

The Containment Spray System consists of four separate trains of equal capacity, capable of meeting 50% of the design basis heat removal capacity. Each train includes a CS/RHP pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage pit (RWSP) supplies borated water to the Containment Spray System.

The Containment Spray System provides a spray of cold borated water into the upper regions of containment to reduce the containment pressure and temperature during a DBA. The RWSP solution temperature is an important factor in determining the heat removal capability of the Containment Spray System.

Heat is removed from the RWSP water by the containment spray/residual heat removal heat exchangers. Two trains of the Containment Spray System provide adequate spray coverage to meet the system design requirements for containment heat removal.

BACKGROUND (continued)

The Containment Spray System is actuated either automatically by a High-3 containment pressure signal or manually. An automatic actuation opens the CS/RHR pump discharge valves and starts the CS/RHR pumps. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. The Containment Spray System maintains an equilibrium temperature between the containment atmosphere and RWSP water.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each CSS train required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

APPLICABLE SAFETY ANALYSES

The Containment Spray System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered relative to Containment integrity are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and 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 one Class 1E bus is out of service and the loss of another Class 1E bus, which is the worst case single active failure and results in two trains of Containment Spray System being inoperable.

The analysis and evaluation show that, under the worst case scenario, the highest peak containment pressure is 59.5 psig experienced during a LOCA. The analysis shows that the peak containment temperature is 355°F experienced during an SLB. Both results meet the intent of the design basis. See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5, “Containment Temperature” for a detailed discussion. The analyses and evaluations assume a unit specific power level of 100%, two containment spray trains operating, and initial (pre-accident) containment conditions of 120°F and 2 psig. The analyses also assume a response time delayed initiation in order to provide conservative peak calculated containment pressure and temperature responses.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a -3.9 psig containment pressure and is associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4.

The modeled Containment Spray System actuation from the containment analysis is based upon a response time associated with exceeding the High-3 containment pressure setpoint to achieving full flow though the containment spray nozzles. The Containment Spray System total response time of 243 seconds includes Class 1E gas turbine generator (GTG) startup (for loss of offsite power), block loading of equipment, CS/RHR pump startup, and spray line filling (Ref. 3).

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

LCO

During a DBA, a minimum of two containment spray trains are required to maintain the containment peak pressure and temperature below the design limits (Ref. 4). To ensure that these requirements are met, three containment spray trains must be OPERABLE. Therefore, in the event of an accident, at least two trains operate, assuming the worst case single active failure occurs.

Each Containment Spray System typically includes a CS/RHR pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWSP upon an ESF actuation signal.

This LCO is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the CS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains.

In MODES 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 MODES 5 and 6.

ACTIONS

A.1 [and A.2]

If one of the required containment spray trains is inoperable, it must be restored to OPERABLE status within 72 hours.   With a required containment spray train inoperable, the system is capable of providing 100% of the heat removal needs for a DBA . [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a risk informed completion time (RICT). This Required Action is not applicable in MODE 4.] The 72 hours Completion Time was chosen because of the low probability of DBA occurring during this period.

B.1 and B.2

If any of the Required Actions or associated Completion Times for Condition A 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 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves, excluding check valves, in the Containment Spray System flow path provides assurance that the proper flow path exists 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 positions prior to being secured. This SR does not require testing or valve manipulation. Rather, it involves verification that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position. [The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.6.6.2

Verifying that each CS/RHR pump's developed head at the flow test point is greater than or equal to the required developed head ensures that CS/RHR pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Since the CS/RHR 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3 and SR 3.6.6.4

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each CS/RHR pump starts upon receipt of an actual or simulated High-3 containment pressure signal. This Surveillance 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 engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.6.6.5

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and that spray coverage of the containment during an accident is not degraded. [Because of the passive design of the nozzle, a test at the first refueling and at 10 year intervals is considered adequate to detect obstruction of the spray nozzles. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40.

2. 10 CFR 50, Appendix K.

3. Subsection 15.6.5.5.

4. Subsection 6.2.1.

5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Six MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in Chapter 10 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open the valves following a turbine reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in Chapter 15 (Ref. 3). Of these, the full power turbine trip without steam dump is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

The safety analysis demonstrates that the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. One turbine trip analysis is performed assuming primary system pressure control via operation of the pressurizer spray. This analysis demonstrates that the DNB design basis is met. Another analysis is performed assuming no primary system pressure control, but crediting reactor trip on high pressurizer pressure and operation of the pressurizer safety valves. This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure. All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

APPLICABLE SAFETY ANALYSES (continued)

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the main steam relief or turbine bypass valves. The Chapter 15 safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization may be determined by system transient analyses or conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if one or more MSSVs on a single steam generator are inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for such case, it is necessary to prevent this power increase by lowering the Power Range Neutron Flux-High setpoint to an appropriate value.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand.

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

LCO

The accident analysis requires that six MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 102% RTP. The LCO requires that six MSSVs per steam generator be OPERABLE in compliance with Reference 2, and the DBA analysis.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, to relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB, or Main Steam System integrity.

APPLICABILITY

In MODES 1, 2, and 3, six MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1 and A.2

In the case of one or more steam generators with one or more MSSVs inoperable, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Required Action A.1 requires an appropriate reduction in reactor power within 4 hours. An additional 32 hours is allowed in Required Action A.2 to reduce the setpoints. The Completion Time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period. The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

BASES

ACTIONS (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 6, with an appropriate allowance for calorimetric power uncertainty.

To determine the maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs, the governing heat transfer relationship is the equation $q = \dot{m}\,\Delta h$, where q is the heat input from the primary side, $\dot{m}$ is the mass flow rate of the steam, and Δh is the increase in enthalpy that occurs in converting the secondary side water to steam. If it is conservatively assumed that the secondary side water is all saturated liquid (i.e., no subcooled feedwater), then the Δh is the heat of vaporization (h_{fg}) at the steam relief pressure. The following equation is used to determine the maximum allowable power level for continued operation with inoperable MSSV(s):

Maximum NSSS Power $\leq$ (100/Q) ($w_s h_{fg} N$) / K

where:

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat), MWt

K = Conversion factor, 947.82 (Btu/sec)/MWt

w_s = Minimum total steam flow rate capability of the OPERABLE MSSVs on any one steam generator at the highest OPERABLE MSSV opening pressure, including tolerance and accumulation, as appropriate, lbm/sec.

h_{fg} = Heat of vaporization at the highest MSSV opening pressure, including tolerance and accumulation as appropriate, Btu/lbm.

N = Number of steam generators in the plant.

To determine the Table 3.7.1-1 Maximum Allowable Power for Required Actions A.1 and A.2 (%RTP), the Maximum NSSS Power calculated using the equation above is reduced by 9% RTP to account for Nuclear Instrumentation System trip channel uncertainties.

Required Action A.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3 the reactor protection system trips specified in LCO 3.3.1, "Reactor Trip System Instrumentation," provide sufficient protection

ACTIONS (continued)

B.1 and B.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 5 inoperable MSSVs per steam generator, 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 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination,

b. Seat tightness determination,

c. Setpoint pressure determination (lift setting),

d. Compliance with owner's seat tightness criteria, and

e. Verification of the balancing device integrity on balanced valves.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 1% setpoint tolerance for OPERABILITY; and, the valves are reset to remain within ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

BASES

REFERENCES

1. Subsection 10.3.2.3.2.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.

3. Section 15.2.

4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

5. ANSI/ASME OM-1-1987.

6. NRC Information Notice 94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and emergency feedwater (EFW) pump turbine steam supply, to prevent MSSV and EFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, turbine bypass system, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by low steam line pressure, steam line pressure negative rate high, or high-high containment pressure. The MSIVs fail closed on loss of control air.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in Chapter 10 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in Chapter 6 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in Chapter 15 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The limiting case for the containment analysis is the SLB inside containment, with a loss of offsite power following turbine trip, and failure of the MSIV on the affected steam generator to close. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the MSIV to close, the additional mass and energy in the steam headers downstream from the other MSIV

BASES

APPLICABLE SAFETY ANALYSES (continued)

contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. A HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

APPLICABLE SAFETY ANALYSES (continued)

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

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

LCO

This LCO requires that four MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIVs are closed, and the steam generator energy is low.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

<u>A.1 [and A.2]</u>

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

BASES

ACTIONS (continued)

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, 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 MODE 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

BASES

ACTIONS (continued)

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed 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 at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5 seconds. The MSIV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. As the MSIVs are not tested at power, they are exempt from the ASME Code (Ref. 5), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

This SR verifies that each MSIV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. [The Frequency of MSIV testing is every 24months. The 24month Frequency for testing 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 10.3.2.3.4.
2. Subsection 6.2.1.
3. Subsection 15.1.5.
4. 10 CFR 100.11.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs), Main Feedwater Regulation Valves (MFRVs), Main Feedwater Bypass Regulation Valves (MFBRVs), and Steam Generator Water Filling Control Valve (SGWFCVs)

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs , MFBRVs, and SGWFCVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs, MFRVs, MFBRVs, and SGWFCVs terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs, MFRVs, MFBRVs, or SGWFCVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs, MFRVs, MFBRVs, and SGWFCVs, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs, MFRVs, MFBRVs, and SGWFCVs, isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of emergency feedwater (EFW) to the intact loops.

One MFIV, one MFRV, one MFBRV, and one SGWFCV, are located on each MFW line, outside but close to containment. The MFIVs, MFRVs , MFBRVs, and SGWFCVs are located upstream of the EFW injection point so that EFW may be supplied to the steam generators following MFIV, MFRV, MFBRV, or SGWFCV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to EFW reaching the steam generator following either an SLB or FWLB.

BASES

BACKGROUND (continued)

All main feedwater valves, MFIVs, MFRVs, MFBRVs, and SGWFCVs close on receipt of any of the following Main Feedwater Isolation signals: high-high steam generator water level, ECCS actuation, or manual actuation.

A description of the MFIVs ,MFRVs, MFBRVs, and SGWFCVs is found in Chapter 10 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs ,MFRVs, MFBRVs and SGWFCVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs, MFRVs, MFBRVs, and SGWFCVs, may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of high-high steam generator water level signal or a safety injection signal.

Failure of an MFIV, MFRV, MFBRV, or SGWFCV to close following an SLB or FWLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

The MFIVs, MFRVs, MFBRVs, and SGWFCVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFIVs, MFRVs, MFBRVs, and SGWFCVs will isolate MFW flow to the steam generators, following an FWLB or main steam line break. These valves will also isolate the nonsafety related portions from the safety related portions of the system.

This LCO requires that four MFIVs, four MFRVs, four MFBRVs, and four SGWFCVs be OPERABLE. The MFIVs, MFRVs, MFBRVs, and SGWFCVs are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. If a feedwater isolation signal on high steam generator level is relied on to terminate an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIVs, MFRVs, MFBRVs, and SGWFCVs must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MFIVs, MFRVs, MFBRVs, and SGWFCVs are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, MFBRVs, and SGWFCVs are normally closed since MFW is not required.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

BASES

ACTIONS (continued)

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

C.1 and C.2

With one MFBRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFBRVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

BASES

ACTIONS (continued)

D.1 and D.2

With one SGWFCVs in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable SGWFCVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

E.1

With two inoperable valves in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. Although the containment can be isolated with the failure of two valves in parallel in the same flow path, the double failure can be an indication of a common mode failure in the valves of this flow path, and as such, is treated the same as a loss of the isolation capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV, MFRV, MFBRV, or SGWFCV or otherwise isolate the affected flow path.

BASES

ACTIONS (continued)

F.1 and F.2

If the MFIV(s), MFRV(s), MFBRV(s), and SGWFCV(s) cannot be restored to OPERABLE status, or closed, or isolated 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 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFIV, MFRV, MFBRV, and SGWFCV is ≤ 5 seconds. The MFIV, MFRV, MFBRV, and SGWFCV isolation times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code (Ref. 2), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program.

SR 3.7.3.2

This SR verifies that each MFIV, MFRV, MFBRV, and SGWFCV can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage.

[The Frequency for this SR is every 24 months. The 24 month Frequency for testing 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES	1.	Subsection 10.4.7.2.2.
	2.	ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.4 Main Steam Depressurization Valves (MSDVs)

BASES

BACKGROUND	The MSDVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Turbine Bypass System to the condenser not be available, as discussed in Chapter 10 (Ref. 1). This is done in conjunction with the Emergency Feedwater System providing cooling water from the emergency feedwater pit (EFP). The MSDVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Turbine Bypass System. One MSDV line for each of the four steam generators is provided. Each MSDV line consists of one MSDV and an associated block valve. The MSDVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The MSDVs are motor operated valves with modulation capability to permit control of the cooldown rate. A description of the MSDVs is found in Reference 1. The MSDVs are OPERABLE with only a DC power source available. In addition, handwheels are provided for local manual operation.
APPLICABLE SAFETY ANALYSES	The design basis of the MSDVs is established by the capability to cool the unit to RHR entry conditions. The design rate of 50°F per hour is applicable for two steam generators, each with one MSDV. This rate is adequate to cool the unit to RHR entry conditions with two steam generators and two MSDVs, utilizing the cooling water supply available in the EFP.

APPLICABLE SAFETY ANALYSES (continued)

In the accident analysis presented in Reference 2, the MSDVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the MSDVs. The number of MSDVs required to be OPERABLE to satisfy the SGTR accident analysis requirements depends upon the number of unit loops and consideration of any single failure assumptions regarding the failure of one MSDV to open on demand.

The MSDVs are equipped with block valves in the event an MSDV fails to close during use.

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

LCO

Four MSDV lines are required to be OPERABLE. One MSDV line is required from each of four steam generators to ensure that at least two MSDV lines are available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second MSDV line on an unaffected steam generator. The block valves must be OPERABLE to isolate a failed open MSDV line.

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the turbine bypass system. A closed block valve does not render it or its MSDV line inoperable if operator action time to open the block valve is supported in the accident analysis.

An MSDV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand.

APPLICABILITY

In MODES 1, 2, and 3, the MSDVs are required to be OPERABLE.

In MODE 4, 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1 [and A.2]

With one required MSDV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE MSDV lines, a nonsafety grade backup in the turbine bypass system, and MSSVs. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

B.1 [and B.2]

With two or more MSDV lines inoperable, action must be taken to restore all but one MSDV line to OPERABLE status. Since the block valve can be closed to isolate an MSDV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable MSDV lines, based on the availability of the turbine bypass system and MSSVs, and the low probability of an event occurring during this period that would require the MSDV lines. [Required Action B.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

C.1 and C.2

If the MSDV lines 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 4, within 12 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the MSDVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the MSDVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an MSDV during a unit cooldown may satisfy this requirement. [The Frequency of 24 months 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.4.2

The function of the block valve is to isolate a failed open MSDV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. [The Frequency of 24 months 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 10.3.2.3.3.
2. Subsection 15.6.3.

B 3.7 PLANT SYSTEMS

B 3.7.5 Emergency Feedwater System (EFWS)

BASES

BACKGROUND

The EFWS automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The EFW pumps take suction through separate and independent suction lines from one of the two EFW pits (LCO 3.7.6) and pumps to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping outside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or main steam depressurization valves (MSDVs) (LCO 3.7.4).

The EFWS consists of two motor driven EFW pumps and two turbine driven pumps configured into four trains. Each motor driven pump provides 50% of EFW flow capacity, and each turbine driven pump provides 50% of the required capacity to the steam generators, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven EFW pump is powered from an independent Class 1E power supply. Each turbine driven EFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven EFW pump.

The Emergency Feedwater Pump Area HVAC System is a support system that provides temperature control for the EFW Pump Areas, and includes electric heating coils, cooling coils, fans, filters, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each EFW pump required to be OPERABLE, the associated train of Emergency Feedwater Pump Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

During normal plant operation (without on-line maintenance (OLM)), all EFW pump discharge cross-connect line isolation valves are closed. Each one of the four EFW pumps is able to supply feedwater separately to each steam generator. During OLM, all the EFW pump discharge cross-connect line isolation valves are opened. Each EFW pump is able to supply feedwater to all steam generators.

BASES

BACKGROUND (continued)

The EFWS is capable of supplying feedwater to the steam generators during safe shutdown, transient and accident conditions.

The turbine driven EFW pumps supply EFW using DC powered control valves actuated to the appropriate steam generator by the engineered safety feature actuation system (ESFAS).

Any two of the four EFW pumps at full flow are sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the EFWS is met.

The EFWS is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs plus 3% margin. Subsequently, the EFWS supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the MSDVs.

The EFWS actuates automatically on low steam generator water level by the ESFAS (LCO 3.3.2). The system also actuates on loss of offsite power, safety injection, and trip of all MFW pumps.

The EFWS is discussed in Chapter 10 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The EFWS mitigates the consequences of any event with loss of normal feedwater.

The design basis of the EFWS is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3% margin.

In addition, the EFWS must supply enough makeup water to replace the secondary steam generator inventory lost as the unit cools to MODE 4 conditions. Sufficient EFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting design basis accidents (DBAs) and transients for the EFWS are as follows:

a. Feedwater line break (FWLB) and

b. Loss of MFW.

In addition, the minimum available EFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES (continued)

The EFWS design is such that it can perform its function following an FWLB between the MFIVs and containment, combined with a loss of offsite power following turbine trip, and a single active failure of the EFW pump.

The EFW flow to the faulty steam generator is automatically terminated by the RPS (high SG water level coincident with reactor trip and no low main steam line pressure signal, and at low main steam line pressure) Sufficient flow would be delivered to the intact steam generator by the redundant EFW pump.

The ESFAS automatically actuates the EFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC power operated valves are provided for each EFW line to control the EFW flow to each steam generator.

The EFWS satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides assurance that the EFWS will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Four independent EFW pumps in four diverse trains are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure during non-OLM. This is accomplished by powering two of the pumps by independent emergency buses. The third and fourth EFW pumps are powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

During OLM, three of four independent EFW pumps in three of the four diverse trains are required to be OPERABLE. This LCO may be changed from Required Action A or B when the EFW pump discharge cross-connect line isolation valves are closed if an EFW train becomes inoperable during non-OLM.

The EFWS is configured into four trains. The EFWS is considered OPERABLE when the components and flow paths required to provide redundant EFW flow to the steam generators are OPERABLE.

This requires that four EFW pumps be OPERABLE in four diverse paths, each supplying EFW to separate steam generators during non-OLM.

During OLM, three FW pumps shall be OPERABLE and shall be capable of supplying EFW to any of supplying EFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the EFWS is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the EFWS is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the EFWS may be used for heat removal via the steam generators. See the BASES for 3.4.6.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the EFWS is not required.

ACTIONS

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

<u>A.1 and A.2</u>

If one of the two steam supplies to one turbine driven EFW train is inoperable, or if a turbine driven pump is inoperable while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days or open all EFW pump discharge cross-connect line isolation valves within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of a steam supply to the turbine driven EFW pump, the 7 day Completion Time is reasonable since there is a redundant steam supply line for the turbine driven pump.

b. For the inoperability of a turbine driven EFW pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion Time is reasonable due to the minimal decay heat levels in this situation.

BASES

ACTIONS (continued)

c. For both the inoperability of a steam supply line to the turbine driven pump and an inoperable turbine driven EFW pump while in MODE 3 immediately following a refueling outage, the 7 day Completion Time is reasonable due to the availability of redundant OPERABLE motor driven EFW pumps, and due to the low probability of an event requiring the use of the turbine driven EFW pump.

Condition A is modified by a Note which limits the applicability of the Condition to when the unit has not entered MODE 2 following a refueling. Condition A allows one EFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

B.1

With one of the required EFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore to OPERABLE status within 72 hours or open all EFW pump discharge cross-connect line isolation valves within 72 hours . This Condition includes the loss of two steam supply lines to the turbine driven EFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the EFWS, time needed for repairs, and the low probability of a DBA occurring during this time period.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two required EFW trains are inoperable in MODE 1, 2, or 3, 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 4 within 12 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.

In MODE 4 with two required EFW trains inoperable, operation is allowed to continue because only one or two motor driven pump EFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

ACTIONS (continued)

D.1

If three EFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one additional EFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one additional EFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the EFWS water and steam supply flow paths provides assurance that the proper flow paths will exist for EFW 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 does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The SR is modified by a Note that states one or more EFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the EFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since EFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the EFWS, OPERABILITY (i.e., the intended safety function) continues to be maintained.

[The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each EFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that EFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref 2). Because it is undesirable to introduce cold EFW into the steam generators while they are operating, this testing is performed on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.5.3

This SR verifies that EFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance 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 engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

The SR is modified by a Note that states one or more EFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the EFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since EFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the EFWS, OPERABILITY (i.e., the intended safety function) continues to be maintained.

This SR is modified by a Note that states the SR is not required in MODE 4. In MODE 4, the required EFW train is already aligned and operating.

<u>SR 3.7.5.4</u>

This SR verifies that the EFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each EFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the autostart function is not required. [The 24 month Frequency 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] However, for the turbine driven EFW train, this SR must be performed when steam is available to run the pump.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. The Note 2 states that one or more EFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the EFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since EFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the EFWS. OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.5

This SR verifies that the EFW is properly aligned by verifying the flow paths from the EFW pits to each steam generator prior to entering MODE 2 after more than 30 days in any combination of MODE 5 or 6 or defueled. OPERABILITY of EFW flow paths must be verified before sufficient core heat is generated that would require the operation of the EFWS during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure EFWS alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the EFW pits to the steam generators is properly aligned.

REFERENCES

1. Subsection 10.4.9.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.6 Emergency Feedwater Pit (EFW Pit)

BASES

BACKGROUND

The two EFW Pits provide safety grade sources of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The EFW Pits provide a passive flow of water, by gravity, to the Emergency Feedwater (EFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the main steam depressurization valves. The EFW pumps operate with a continuous recirculation to the EFW Pits.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the turbine bypass system. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the EFW Pits are principal components in removing residual heat from the RCS, they are designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena. The EFW Pits are designed to Seismic Category I to ensure availability of the feedwater supply. Feedwater is also available from alternate sources.

A description of the EFW Pits is found in Chapter 10 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The EFW Pits provide cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in Chapters 6 and 15 (Refs. 2 and 3, respectively). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 2 hours at MODE 3, steaming through the MSSVs, followed by a cooldown to residual heat removal (RHR) entry conditions at the design cooldown rate.

The limiting event for the EFW Pits volume is the large feedwater line break coincident with a loss of offsite power.

The EFW Pits satisfy Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

To satisfy accident analysis assumptions, the EFW Pits must contain sufficient cooling water to remove decay heat for 2 hours following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the EFW pumps during cooldown, as well as account for any losses from the steam driven EFW pump turbine, or before isolating EFW to a broken line.

The level required for each EFW Pit is equivalent to a usable volume of ≥ 204,850 gallons, which is based on holding the unit in MODE 3 for 8 hours, followed by a cooldown to RHR entry conditions within 6 hours. This basis is established in Reference 1 and exceeds the volume required by the accident analysis.

The OPERABILITY of the EFW Pits is determined by maintaining the pit level at or above the minimum required level.

APPLICABILITY

In MODES 1, 2, and 3, the EFW Pits are required to be OPERABLE.

In MODE 4, 5 or 6, the EFW Pits are not required because the EFW System is not required.

ACTIONS

A.1, A.2.1, [and A.2.2]

If the one or both EFW Pits are not OPERABLE, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the EFW pumps are OPERABLE, and that the backup supply has the required volume of water available. Both EFW Pits must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the EFW Pits. [Required Action A.2.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time.]

ACTIONS (continued)

B.1 and B.2

If both EFW Pits 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 4, within 12 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

This SR verifies that each EFW Pit contains the required volume of cooling water. [The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the EFW Pit inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the EFW Pit level. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 10.4.9.2.1.

2. Subsection 6.2.1.4.

3. Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

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

A typical CCW System is arranged as four independent, 50% capacity cooling loops, and has isolatable nonsafety related components. Each safety related train includes one 50% capacity pump, connection to one of the two surge tanks, a 50% capacity heat exchanger, piping, valves, and instrumentation. Each safety related train is powered from a separate bus. The surge tanks in the system provide pump trip protective functions to ensure that sufficient net positive suction head is available. The pump in each train is automatically started on receipt of a safety injection signal, and all nonessential components are isolated.

The Safety Related Component Area HVAC System is a support system that provides temperature control for the CCW Pump Areas, and includes electric heating coils, cooling coils, fans, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each CCW train required to be OPERABLE, the associated train of Safety Related Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

Additional information on the design and operation of the system, along with a list of the components served, is presented in Chapter 9 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the residual heat removal (RHR) system. This may be during a normal or post accident cooldown and shutdown. CCWS cooling to the four RCP seal thermal barriers is used for all operating modes (including accident and safe shutdown) to preclude a RCP seal LOCA in the event that CVCS is unavailable to provide required flow to the RCP seal via seal injection. Manual alignment of RCP thermal barrier cooling is achieved via the CCWS RCP cross-tie valves from the MCR in the event two CCWS trains are unavailable to supply CCWS to a pair of RCP thermal barriers.

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for two CCW trains to remove the post loss of coolant accident (LOCA) heat load from the refueling water storage pit and other components, such as Safety Injection Pumps and CS/RHR Pumps. The Emergency Core Cooling System (ECCS) LOCA and containment OPERABILITY LOCA each model the maximum and minimum performance of the CCW System, respectively. The normal temperature of the CCW is 100°F, and, during unit cooldown to MODE 5 (T_{cold} < 200°F), a maximum temperature of 110°F is assumed. This prevents the refueling water storage pit fluid from increasing in temperature following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System (RCS).

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System also functions to cool the unit from RHR entry conditions (T_{cold} < 350°F), to MODE 5 (T_{cold} < 200°F), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the number of CCW and RHR trains operating. Two CCW trains are sufficient to remove decay heat during subsequent operations with T_{cold} < 200°F. This assumes a maximum service water temperature of 95°F occurring simultaneously with the maximum heat loads on the system.

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

LCO

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

A CCW train is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE and

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

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the CS/RHR heat exchanger.

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

ACTIONS

A.1 [and A.2]

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," be entered if an inoperable CCW train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one of the required CCW trains is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining two OPERABLE CCW trains are adequate to perform the heat removal function. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Required Action is not applicable in MODE 4.] The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE trains, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW train 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

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

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.7.2

This SR verifies that CCW train leakage is within the limits necessary to assure that an adequate water volume is maintained in each CCW surge tank compartment for cooling required loads for 7 days after a postulated seismic event with no makeup water source. Successful completion of this test provides assurance that CCWS component leakage during the operating cycle would not prevent CCWS function without surge tank makeup for at least 7 days. [The 92 day Frequency is based on engineering judgment and was chosen to provide added assurance that a potential existing leak during power operation would not be so large as to prevent CCWS operation for 7 days if makeup were unavailable. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The leak rate of 3 gallons per hour is based on the water volume in each tank compartment between the low-low level setpoint and instrument zero; this volume is greater than 800 gallons. A train leak rate of 3 gallons per hour would require more than 7 days to deplete the compartment of this water volume. (The leak rate value is conservatively selected to account for measurement uncertainty and margin.) The low-low level setpoint is below the normal operating level of each compartment. The zero level is above the pump suction nozzle elevation used for CCWS pump NPSH calculations. Thus, surveillance of this leak rate assures that surge tank compartment water volume is adequate to support CCWS operation for a minimum of 7 days without makeup. During the surveillance, it is necessary to minimize fluctuations in CCWS heat load and potential temperature fluctuations that could affect level indication. If the surveillance result is not within allowable limits for a CCW train, that train will be declared inoperable and additional testing may be necessary to determine if the header tie line isolation valves (NCS-MOV-007A/B/C/D, NCS-MOV-020A/B/C/D) are degraded. If it is determined that train separation cannot be achieved due to abnormal leakage through a pair of the redundant header tie line isolation valves (e.g., NCS-MOV-007A and NCS-MOV-007B), then both of the affected trains will be declared inoperable.

The duration of SR 3.7.7.2 testing should be long enough for the installed instrumentation to accurately measure the system losses with considerations of environmental changes in temperatures affecting thermal contraction and expansion of water within the CCWS surge tanks.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

This SR verifies isolation valves between safety and non-safety portions of the CCWS that cannot be tested during power operation. Such valves, notably NCS-AOV-057A/B and NCS-AOV-058A/B, cannot be tested during power operation because closure of these valves would isolate important components associated with normal operation. However, these valves are not normally cycled during power operation; thus, their leak rate is not likely to significantly change after the test is performed and the valves are restored to the position required for power operation. The valves are tested using a local leak rate test method. The total calculated leakage from isolation valves for each subsystem shall not exceed 25 gallons per 7 days. Successful completion of this test provides assurance that leakage from these valves isolating will not prevent CCWS function without surge tank makeup for at least 7 days. [The 24 month Frequency 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.4

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance 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 engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.7.5

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. [The 24 month Frequency 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 9.2.2.

B 3.7 PLANT SYSTEMS

B 3.7.8 Essential Service Water System (ESWS)

BASES

BACKGROUND

The ESWS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the ESWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The ESWS consists of four separate, safety related, cooling water trains. Each train consists of one 50% capacity pump, one component cooling water (CCW) heat exchanger, one essential chiller unit, piping, valves, instrumentation, and two types of strainers. The pumps and valves are remote and manually aligned, except in the unlikely event of a loss of coolant accident (LOCA). The pumps aligned to the critical loops are automatically started upon receipt of a safety injection signal, and all essential valves are aligned to their post accident positions.

Additional information about the design and operation of the ESWS, along with a list of the components served, is presented in Chapter 9 (Ref. 1). The principal safety related function of the ESWS is the removal of decay heat from the reactor via the CCW System.

[[The Safety Related Component Area HVAC System is a support system that provides temperature control for the ESW Pump Areas, and includes electric heating coils, cooling coils, fans, and instrumentation and controls necessary to perform the support function. The ESWS is a support system and provides cooling water to the essential chiller unit. The Essential Chilled Water System (ECWS) is a support system and provides chilled water to the air handling unit cooling coil. For each ESW train required to be OPERABLE, the associated train of Safety Related Component Area HVAC System, including its associated train of the ECWS and ESWS, must be in operation, or available to operate on demand, and capable of performing its related support function.]]

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the ESWS is for two ESWS trains, in conjunction with the CCW System to remove core decay heat following a design basis LOCA. This prevents the refueling water storage pit fluid from increasing in temperature following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System. The ESWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The ESWS, in conjunction with the CCW System, also cools the unit from RHR residual heat removal (RHR), as discussed in Chapter 5, (Ref. 2) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCW and CS/RHR System trains that are operating.

Two ESWS trains are sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum ESWS temperature of 95°F occurring simultaneously with maximum heat loads on the system.

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

LCO

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

An ESWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The pump is 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 ESWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the ESWS and required to be OPERABLE in these MODES.

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

ACTIONS

A.1 [and A.2]

If one of the required ESWS trains is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE ESWS trains are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ESWS trains could result in loss of ESWS function. Required Action A.1 is modified by two Notes.

ACTIONS (continued)

The Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable ESWS train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Required Action is not applicable in MODE 4.] 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 ESWS train 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 3.7.8.1

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

Verifying the correct alignment for manual, power operated, and automatic valves in the ESWS flow path provides assurance that the proper flow paths exist for ESWS 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 being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

[The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

This SR verifies proper automatic operation of the ESWS valves on an actual or simulated actuation signal. The ESWS is a normally operating system that cannot be fully actuated as part of normal testing. This surveillance is tested to assure the requirements of IST program described in Table 3.9-14. The motor operated valve is provided at the discharge of each pump. The starting logic of the ESWP interlocks the motor operated valve with the pump operation. This interlock prevents the pump from starting if the valve is not closed. The closed discharge valve opens after starting the ESWP. This Surveillance 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 engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.8.3

This SR verifies proper automatic operation of the ESWS pumps on an actual or simulated actuation signal. The ESWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. [The 24month Frequency 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 length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES	1.	Subsection 9.2.1.
	2.	Subsection 5.4.7.

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Essential Service Water System (ESWS) and the Component Cooling Water (CCW) system.

[[The UHS consists of four 50 percent capacity mechanical draft cooling towers, one for each ESWS train. Each cooling tower consists of two cells with one fan per cell. The combined inventory of three of the four UHS basins provides a 30-day storage capacity as discussed in FSAR Chapter 9 (Ref. 1). Each unit is provided with its own independent UHS with no cross connection between the two units.]] The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The basic performance requirements are that an adequate inventory of cooling water be available for [[30]] days without makeup, and that the design basis temperatures of safety-related equipment not be exceeded. [[Each UHS basin provides 33-1/3 percent of the combined inventory for the 30-day storage capacity to satisfy the short-term recommendation of Regulatory Guide 1.27 (Ref. 2). There is one safety-related UHS transfer pump per UHS basin which is used to transfer water between the UHS basins.]]

The [[stored]] water level provides adequate net positive suction head (NPSH) to the ESW pump during a 30-day period of operation following the design basis LOCA or safe shutdown with LOOP scenario without makeup.

[[The Safety Related Component Area HVAC System is a support system that provides temperature control for the UHS Transfer Pump Areas, and includes electric heating coils, cooling coils, fans, and instrumentation and controls necessary to perform the support function. The ESWS is a support system and provides cooling water to the essential chiller unit. The Essential Chilled Water System (ECWS) is a support system and provides chilled water to the air handling unit cooling coil. For each UHS Transfer Pump required to be OPERABLE, the associated train of Safety Related Component Area HVAC System, including its associated train of the ECWS and ESWS, must be in operation, or available to operate on demand, and capable of performing its related support function.]]

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1.

BASES

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation.

[[The operating limits are based on safe shutdown with LOOP. A conservative heat transfer analysis for the worst case LOCA was performed to ensure that the cooling tower capacity and the basin water inventory adequately remove the heat load for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure. The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2) which requires a 30 day supply of cooling water in the UHS.]]

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

LCO

[[The UHS is required to be OPERABLE and is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the ESWS to operate for at least 30 days following a design basis LOCA or safe shutdown with LOOP, without makeup water, and provide adequate net positive suction head (NPSH) to the ESWS pumps, and without exceeding the maximum design temperature of the equipment served by the ESWS. To meet this condition, three UHS cooling towers with the UHS temperature not exceeding 93°F during MODES 1, 2, 3 and 4 and the level in each of three basins being maintained above 2,850,000 gallons are required—a volume correspondent to the safe shutdown with LOOP conditions that bounds the LOCA condition. Additionally, three of the UHS transfer pumps shall be OPERABLE, with each pump capable of transferring flow from a UHS basin meeting water inventory and temperature limits, and powered from an independent Class 1E electrical division.]]

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

[[A.1 and A.2

If one of the required cooling towers and associated fans is inoperable (i.e., one or more fans per cooling tower inoperable), action must be taken to restore the inoperable cooling tower and associated fan(s) to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE cooling towers with associated fans are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE UHS cooling towers could result in a loss of UHS function. Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Required Action is not applicable in MODE 4. The 72-hour

ACTIONS (continued)

Completion Time is based on the capability of the OPERABLE cooling towers to provide the UHS cooling capability and the low probability of an accident occurring during the 72 hours that one required cooling tower and associated fans are inoperable.]]

B.1

With water temperature of the UHS [[> 93°F]], the design basis assumption associated with initial UHS temperature is bounded provided the temperature of the UHS averaged over the previous 24-hour period is [[≤ 93°F]]. With the water temperature of the UHS [[> 93°F]], long-term cooling capability of the ECCS loads may be affected. Therefore, to ensure longterm cooling capability is provided to the ECCS loads when water temperature of the UHS is [[> 93°F]], Required Action B.1 is provided to monitor the water temperature of the UHS more frequently and verify the temperature is [[≤ 93°F]] when averaged over the previous 24 hour period. The once per hour Completion Time takes into consideration UHS temperature variations and the increased monitoring frequency needed to ensure design basis assumptions and equipment limitations are not exceeded in this condition. If the water temperature of the UHS exceeds [[93°F]] when averaged over the previous 24 hour period, Condition E must be entered immediately.

[[C.1

If one or more required UHS basins have a water level not within the limits, action must be taken to restore the water level to within limits within 72 hours.

The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hours, the considerable cooling capacity still available in the basin(s), and the time required to reasonably complete the Required Action. Furthermore, there would be no significant loss in the UHS cooling capacity when the water level drops below the normal level during a 72-hour period because of sufficient cooling tower basin inventory. The UHS has a combined design heat removal capacity of approximately 20 days from two operable cooling tower basins and 30 days from three operable cooling tower basins.]]

BASES

ACTIONS (continued)

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

If one or more required UHS transfer pump(s) are inoperable, action must be taken to restore the pump(s) to OPERABLE status or implement an alternate method of transferring the affected basin within 7 days. If an alternate method is utilized, action still must be taken to restore the transfer pump(s) to OPERABLE status within 31 days.

The Completion Times are reasonable based on the low probability of an accident occurring during the time allowed to restore the pump(s) or implement an alternate method, the availability of alternate methods, and the amount of time available to transfer the water from one basin to the other under the worst case accident assumptions. Furthermore, the inoperability of all required transfer pumps leaves only two cooling tower basins with a combined design heat removal capacity of approximately 20 days. This cooling period bounds and justifies the 7-day completion time to restore the transfer pumps to operable status.]]

E.1 and E.2

If the Required Actions and Completion Times of Condition [[A, B, C, or D]] are not met, or the UHS is inoperable for reasons other than Condition [[A, B, C, or D]] the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 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 3.7.9.1

This SR verifies that adequate long term (30 day) cooling can be maintained. The specified level also ensures that sufficient NPSH is available to operate the ESWS pumps. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This SR verifies that [[each]] required UHS [[basin]] water inventory is [[≥ 2,850,000 gallons]]. Plant procedures provide the corresponding water level to be verified to assure a usable volume of [[2,850,000 gallons]], accounting for unusable volume and measurement uncertainty.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

This SR verifies that the ESWS is available to cool the CCW System and essential chiller unit to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a design basis LOCA or safe shutdown with LOOP. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This SR verifies that the water temperature of the UHS is [[≤ 93°F]].

[[SR 3.7.9.3

Operating each cooling tower fan for ≥15 minutes ensures that all fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration, can be detected for corrective action. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]]

[[SR 3.7.9.4

This SR verifies that each UHS fan starts and operates on an actual or simulated actuation signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]]

[[SR 3.7.9.5

This SR verifies that each UHS transfer pump starts and operates on a manual actuation signal. Verification of the UHS transfer pump operation includes testing to verify the pump's developed head at the flow test point is greater than or equal to the required developed head. Testing also includes verification of required valve position.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.6

This SR verifies the correct alignment for manual, power-operated, and automatic valves in the UHS flow path to assure that the proper flow paths exist for UHS 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 being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk, and is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.7

This SR verifies proper manual and automatic operation of the UHS valves on remote manual or on an actual or simulated actuation signal. The UHS is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk, and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR Subsection 9.2.5.

2. Regulatory Guide 1.27.

B 3.7 PLANT SYSTEMS

B 3.7.10 Main Control Room HVAC System (MCRVS)

BASES

BACKGROUND

The MCRVS consists of the main control room emergency filtration system (MCREFS) and the main control room air temperature control system (MCRATCS).

The MCREFS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. The MCRATCS provides air temperature control for the main control room in all conditions.

The MCREFS consists of two independent, redundant trains that recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each MCREFS train consists of a MCR emergency filtration unit that contains, in air-flow order, a prefilter, electric heating coil, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), a high efficiency post-filter, and a fan. Ductwork, dampers, doors, barriers, and instrumentation also form part of the system.

The MCRATCS consists of four independent and redundant trains that provide cooling and heating of recirculated control room air. Each train consists of a MCR air handling unit, instrumentation, and controls to provide for control room temperature control.

During the normal ventilation configuration the MCR air handling units and the MCR toilet/kitchen exhaust fan are operating and perform ventilation and air conditioning inside the CRE.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to the CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

BACKGROUND (continued)

Upon receipt of the MCR isolation signal, the MCR air intake isolation dampers, the MCR toilet/kitchen exhaust line isolation dampers and the MCR smoke purge line isolation dampers (normally closed) are closed, then two MCR emergency filtration units automatically are started. The MCR emergency filtration unit air intake dampers and air return dampers are opened. The prefilters of the MCR emergency filtration unit remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers. Continuous operation of each train for at least 10 hours per month, with the heaters on, reduces moisture buildup on the HEPA filters and adsorbers. The heater is important to the effectiveness of the charcoal adsorbers. The electric heating coils are powered from a Class 1E power source and are designed to maintain the relative humidity of inlet air to the charcoal adsorber banks below 70%. Power to each electric heating coil is interlocked with power to its associated fan (i.e., electric heating coil receives power when fan starts; power is removed when fan stops).

Actuation of the MCRVS places the system in either of two separate emergency modes (pressurization mode for protection from radiation or isolation mode for protection from hazardous chemicals/toxic gas), depending on the initiation signal. Actuation of the system to the pressurization mode of the emergency mode of operation, closes the unfiltered outside air intake and unfiltered exhaust dampers, and aligns the system for recirculation of the air within the CRE through the redundant trains of HEPA and the charcoal filters. The pressurization mode also initiates pressurization and filtered ventilation of the air supply to the CRE.

Outside air is filtered and added to the air being recirculated from the CRE. Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the surrounding areas adjacent to the CRE boundary. The actions taken in the isolation mode are the same, except that the signal switches the MCREFS to an isolation alignment to minimize any outside air from entering the CRE through the CRE boundary.

BACKGROUND (continued)

[The air entering the CRE is continuously monitored by radiation and toxic gas detectors. One detector output above the setpoint will cause actuation of the pressurization mode or isolation mode, as required. The actions of the isolation mode are more restrictive, and will override the actions of the pressurization mode].

A single train of MCREFS operating at a flow ≤600 cfm will pressurize the CRE to about 0.125 inches water gauge relative to external areas adjacent to the CRE boundary. The MCRVS operation in maintaining the CRE habitable is discussed in Chapter 9, Subsection 9.4.1 (Ref. 2).

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The MCREFS is designed in accordance with Seismic Category I requirements.

Two trains of MCRATCS will provide the required temperature control to maintain the control room between 73°F and 78°F. The MCRVS operation in maintaining the control room temperature is discussed in Chapter 9, Section 9.4.1 (Ref. 2).

In order for the MCRATCS train to be considered OPERABLE, the associated train of Essential Chilled Water System must be in operation and capable of performing its related support function to provide chilled water flow to the air handling unit cooling coil upon demand. The Essential Service Water System supports operation of the essential chiller, and the associated train of the Essential Service Water System must also be in operation.

The CRE habitability is maintained by limiting the inleakage of potentially contaminated air into the CRE. The potential leakage paths for the CRE include the control room enclosure (e.g., walls, penetrations, floor, ceilings, joints, etc.) and other potential paths such as pressurized ductwork from other HVAC systems, pressurized air systems (e.g., instrument air) or isolated HVAC intakes.

The MCRVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem total effective dose equivalent (TEDE).

APPLICABLE SAFETY ANALYSES

The MCRVS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The MCREFS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the design basis accident (DBA), fission product release presented in Chapter 15, Subsection 15.6.5.5 (Ref. 3).

The MCRATCS maintains the temperature between 73°F and 78°F.

The emergency pressurization mode of the MCRVS is assumed to operate following a DBA to provide protection from a radiological dose to the CRE occupants. The MCRVS also provides protection from smoke and hazardous chemicals to the CRE occupants. [The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1).] The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown console. (Ref. 2).

The worst case single active failure of a component of the MCRVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

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

LCO

Two independent and redundant MCREFS trains and three of the four independent and redundant MCRATCS are required to be OPERABLE to provide the required redundancy to ensure that the system functions assuming the worst case single active failure occurs coincident with the loss of offsite power. Total system failure, such as from a loss of the required ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem TEDE to the CRE occupants in the event of a large radioactive release and in the equipment operating temperature exceeding limits in the event of an accident.

LCO (continued)

The MCRVS is considered OPERABLE when the individual components necessary to limit CRE occupant exposure and ensure a control room temperature of ≤ 78°F are OPERABLE when the associated:

a. One 100% MCR emergency filtration unit fan and two 50% MCR air handing unit fans are OPERABLE,

b. MCR emergency filtration unit HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions,

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

d. Heating and cooling coils and associated temperature control equipment are capable of performing their function.

In order for the MCREFS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls without requiring entry into the Condition for an inoperable pressure boundary. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies, the MCRVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA and to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

During movement of irradiated fuel assemblies, the MCRVS must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1

When one MCREFS train is inoperable for reasons other than an inoperable CRE boundary (only one MCREFS train OPERABLE), action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE MCREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a single failure in the OPERABLE MCREFS train could result in loss of function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1

When one of the required MCRATCS trains are inoperable (only two MCRATCS trains OPERABLE), action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE MCRATCS trains are adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE MCRATCS trains could result in loss of function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

ACTIONS (continued)

C.1, C.2, and C.3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional and unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protection measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

D.1 and D.2

In MODE 1, 2, 3, or 4, if the inoperable MCRVS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. 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.

ACTIONS (continued)

E.1 and E.2

During movement of irradiated fuel assemblies, if the inoperable MCREFS or/and MCRATCS trains cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE MCRVS trains in the emergency mode. This action ensures that the remaining trains are OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

An alternative to Required Action E.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

[Required Action E.1 is modified by a Note indicating to place the system in the toxic gas protection mode if automatic transfer to the toxic gas protection mode is inoperable.]

F.1

During movement of irradiated fuel assemblies, with required MCRVS inoperable or with required MCRVS inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

G.1

If required MCRVS trains are inoperable in MODE 1, 2, 3, or 4 for reasons other than an inoperable CRE boundary (i.e., Condition C), the MCRVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month provides an adequate check of this system. Monthly heater operations dry out any moisture accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated for ≥10 continuous hours with the heaters energized. [The 31 day Frequency is based on the reliability of the equipment and the two train redundancy. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.10.2

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

SR 3.7.10.3

This SR verifies that each MCRVS train starts and operates on an actual or simulated actuation signal. [The Frequency of 24 months 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 length. This equipment is not at risk of imminent significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

SURVEILLANCE REQUIREMENTS (continued)

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition C must be entered Required Action C.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 4) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 5). These compensatory measures may also be used as mitigating actions as required by Required Action C.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 6). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

SR 3.7.10.5

This SR verifies that the heat removal capability of all potential operating configuration of two trains of 50% capacity MCRATCS air handling units is sufficient to remove the heat load assumed in the safety analyses in the control room. This SR consists of a combination of testing and calculations. [The 24 month Frequency is appropriate since significant degradation of the MCRATCS is slow and is not expected over this time period. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 6.4.4.

2. Subsection 9.4.1.

3. Subsection 15.6.5.5.

4. Regulatory Guide 1.196

5. NEI 99-03, “Control Room Habitability Assessment,” June 2001.

6. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternate Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694).

B 3.7 PLANT SYSTEMS

B 3.7.11 Annulus Emergency Exhaust System

BASES

BACKGROUND

The annulus emergency exhaust system is the engineered safety feature (ESF) filter system that is designed for fission product removal and retention by filtering air it exhausts from the

- Penetration areas
- Safeguard component areas

following accidents. The annulus emergency exhaust system is automatically initiated by ECCS actuation signal and initiated manually during non-ECCS actuation events, and will establish and maintain a -1/4 in. W.G. pressure in the penetration and safeguard component area, within approximately 240 seconds. Airborne radioactive material in the penetration and safeguard component areas is directed to the annulus emergency exhaust system, preventing uncontrolled release to the environment. The annulus emergency exhaust system exhaust fans direct flow to the plant vent stack.

The annulus emergency exhaust system consists of two independent and redundant trains. Each train consists of a prefilter, a high efficiency particulate air (HEPA) filter and a fan. Ductwork, dampers and instrumentation also form part of the system. Each train is protected by normally-closed exhaust and outlet dampers. These dampers block auxiliary building HVAC system flow into each train during normal operation, thus preserving and extending the useful service live of annulus air filtration media. The system initiates filtered ventilation upon ECCS actuation. In addition, the signal starting the annulus emergency exhaust system exhaust fans opens the corresponding exhaust damper to the plant vent stack, and the exhaust dampers from the penetration and safeguard component areas.

The auxiliary building HVAC system ventilates the penetration and safeguard component areas during normal plant operations and refueling, with normally-open isolation dampers located in the associated supply and exhaust ducts. These isolation dampers automatically close on an ECCS actuation signal, while motor-operated dampers in parallel exhaust ducts from the penetration areas, and parallel exhaust ducts from the safeguard component areas automatically open. Both annulus emergency exhaust filtration unit fan trains A and B outlet dampers open when their respective fan starts on ECCS actuation. The prefilters remove any large particles in the air, as well as any entrained water droplets, to prevent excessive loading of the HEPA filters.

BACKGROUND (continued)

The Safety Related Component Area HVAC System is a support system that provides temperature control for the Annulus Emergency Exhaust Filtration Unit Area, and includes electric heating coils, cooling coils, fans, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each annulus emergency exhaust system train required to be OPERABLE, the associated train of Safety Related Component Area HVAC System, including one of its two associated trains of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

The annulus emergency exhaust system is discussed in Subsection 6.5.1 and Subsection 9.4.5 (Refs. 1 and 2 respectively).

APPLICABLE SAFETY ANALYSES

The annulus emergency exhaust system design basis is SAFETY established by the large break loss of coolant accident (LOCA). The system evaluation assumes a passive failure outside containment, such as valve packing leakage during a Design Basis Accident (DBA). The system evaluation also assumes a passive failure of the ECCS outside containment, such as an SI pump seal leakage. In such a case, the system restricts the radioactive release to within the 10 CFR 50.34 (Ref. 4) limits, or the NRC staff approved licensing basis (e.g., a specified fraction of 10 CFR 50.34 limits). The analysis of the effects and consequences of a large break LOCA are presented in Chapter 15, Subsection 15.6.5.5 (Ref. 3). The annulus emergency exhaust system also actuates following a small break LOCA to clean up releases of smaller leaks, such as from valve stem packing.

Either a complete loss of function or excessive LEAKAGE may result in less efficient removal of any gaseous or particulate material released to the penetration areas and the ECCS pump rooms following a LOCA.

The annulus emergency exhaust system satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the annulus emergency exhaust system are required to be OPERABLE to ensure that at least one train is available, assuming there is a single failure disabling the other train coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the penetration and safeguard component areas exceeding 10 CFR 50.34 limits in the event of a Design Basis Accident (DBA).

LCO (continued)

The annulus emergency exhaust system is considered OPERABLE when the individual components necessary to control radioactive releases and maintain the safeguard component areas filtration are OPERABLE in both trains. An annulus emergency exhaust system train is considered OPERABLE when its associated:

a. Fan is OPERABLE,

b. HEPA filter is not excessively restricting flow, and is capable of performing their filtration function, and

c. Ductwork and dampers are OPERABLE.

The LCO is modified by a Note allowing the associated room boundary (e.g., penetration areas, safeguard component areas) to be opened intermittently under administrative controls without requiring entry into the Condition for an inoperable pressure boundary. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for associated room isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the annulus emergency exhaust system is required to be OPERABLE, consistent with the OPERABILITY requirements of the Emergency Core Cooling System (ECCS).

In MODE 5 or 6, the annulus emergency exhaust system is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

With one annulus emergency exhaust system train inoperable, the action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the annulus emergency exhaust system function. The 7 day Completion Time is appropriate because the risk contribution of the annulus emergency exhaust system is less than that of the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. The 7 day Completion Time is based on the low probability of a DBA occurring during this period, and the remaining train providing the required capability.

Concurrent failure of two annulus emergency exhaust system trains would result in the loss of functional capability; therefore, LCO 3.0.3 must be entered immediately.

BASES

ACTIONS (continued)

B.1

If the penetration or safeguard component areas boundary is inoperable, the annulus emergency exhaust system trains cannot perform their intended functions. Actions must be taken to restore an OPERABLE room pressure boundary within 24 hours. During the period that the room boundary is inoperable, appropriate compensatory measures consistent with the intent, as applicable, of GDC 19, 60, 64 and 10 CFR 50.34 should be utilized to protect plant personnel from potential hazards such as radioactive contamination, toxic chemicals, smoke, temperature and relative humidity, and physical security. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possibly repair, and test most problems with the room pressure boundary.

C.1 and C.2

If the inoperable train or room pressure boundary 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 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 3.7.11.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system. Systems without heaters need only be operated for ≥15 minutes. [The 31 day Frequency is based on the known reliability of equipment and the two train redundancy available. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.11.2

This SR verifies that the required annulus emergency exhaust system testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, and minimum flow rate. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.11.3

This SR verifies that the annulus emergency exhaust system starts and operates on an actual or simulated actuation signal. [The 24 month Frequency 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 length. This equipment is not at risk of imminent significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.7.11.4

The Annulus Emergency Exhaust System produces a negative pressure to prevent leakage from the penetration and safeguard component areas. This SR verifies that the penetration and safeguard component areas can be rapidly drawn down to at a ≤-0.25 inches water gauge relative to atmospheric pressure. This SR verifies the integrity of the penetration and safeguard component areas enclosure. The ability of the penetration and safeguard component areas to draw down and maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper function of annulus emergency exhaust system. During the accident condition, Each annulus emergency exhaust system train is designed to draw down to at a ≤-0.25 inches water gauge relative to atmospheric pressure within 240 seconds after a start signal and maintain a ≤-0.25 inches water gauge relative to atmospheric pressure at a flow rate of 5600 cfm in the associated room, with respect to adjacent areas, to prevent unfiltered LEAKAGE. [The Frequency of 24 months is also consistent with the guidance provided in NUREG-0800 (Ref. 6). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

The minimum system flow rate maintains a slight negative pressure in the penetration and safeguard component areas, and provides sufficient air velocity to transport particulate contaminants, assuming only one filter train is operating. The number of filter elements is selected to limit the flow rate through any individual element to about 5600 cfm. This may vary based on filter housing geometry. The maximum limit ensures that the flow through, and pressure drop across, each filter element are not excessive.

The filters have a certain pressure drop at the design flow rate when clean. The magnitude of the pressure drop indicates acceptable performance, and is based on manufacturers' recommendations for the filter at the design flow rate. An increase in pressure drop or a decrease in flow indicates that the filter is being loaded or that there are other problems with the system.

[This test is conducted along with the tests for filter penetration; thus, the 24 month Frequency is consistent with that specified in Reference 5. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 6.5.1.

2. Subsection 9.4.5.

3. Subsection 15.6.5.5.

4. 10 CFR 50.34.

5. Regulatory Guide 1.52, Rev. 3.

6. NUREG-0800, Section 6.5.1, Rev. 3, March 2007.

B 3.7 PLANT SYSTEMS

B 3.7.12 Spent Fuel Pit Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel pit meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel. A general description of the spent fuel pit design is given in Chapter 9 (Ref. 1). A description of the Spent Fuel Pit Purification and Cooling System is given in Chapter 9 (Ref. 1). The assumptions of the fuel handling accident are given in Chapter 15 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The minimum water level in the spent fuel pit meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 3). The resultant 2 hour total effective dose equivalent per person at the exclusion area boundary is a small fraction of the 10 CFR 50.34 (Ref. 4) limits. According to Reference 3, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pit surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 3 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle. To offset this small nonconservatism, the analysis conservatively assumes that all fuel rods fail. The spent fuel pit water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The spent fuel pit water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel storage and movement within the spent fuel pit.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel pit since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel pit water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel pit is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies sufficient spent fuel pit water is available in the event of a fuel handling accident. The water level in the spent fuel pit must be checked at the start of spent fuel movement campaign and periodically. [The 7 day Frequency is appropriate because the volume in the pit is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

During refueling operations, the level in the spent fuel pit is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.7.1.

REFERENCES

1. Section 9.1.
2. Subsection 15.7.4.
3. Regulatory Guide 1.183, July 2000.
4. 10 CFR 50.34.

B 3.7 PLANT SYSTEMS

B 3.7.13 Spent Fuel Pit Boron Concentration

BASES

BACKGROUND

The spent fuel pit is a single region spent fuel rack design with 11.1 in center-to-center rack spacing. The spent fuel pit stores 900 spent fuel assemblies in borated water without credit for fuel burnup.

The water in the spent fuel pit normally contains soluble boron which results in large subcriticality margins under actual operating conditions. The maximum Keff without taking credit for soluble boron is

well below 0.95, which is the criticality safety design criteria in 10 CFR 50.68(b)(4) being adopted in designing the spent fuel racks. The double contingency principle discussed in ANSI/ANS-8.1-1998 (R2007), however, allows credit for soluble boron under abnormal or accident conditions since only a single accident scenario need be considered at a time.

APPLICABLE SAFETY ANALYSES

Most accident conditions do not result in an increase in the reactivity of the spent fuel pit. Examples of these accident conditions, as determined from criticality analysis, are the dropping of a fuel assembly onto the top of the rack and misloading of a fresh fuel assembly of the highest anticipated reactivity into a spent fuel rack cell. However, accidents that could increase reactivity can be postulated. This increase in reactivity is unacceptable with unborated water in the spent fuel pit . Accidents that can be postulated are associated with the mislocation of a fresh fuel assembly and rack movements in the event of seismic activity. The minimum soluble boron concentration to maintain subcriticality in the SFP during these accident conditions is 800 ppm, as determined from criticality analysis. The negative reactivity effect of the soluble boron compensates for the increased reactivity caused by these postulated accident scenarios. Subcriticality conditions, therefore, are maintained through compliance with the LCO minimum limit of ≥4000 ppm soluble boron.

The concentration of dissolved boron in the spent fuel pit satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The spent fuel pit boron concentration is required to be ≥ 4000 ppm according to the RWSP and refueling requirements. The specified concentration of dissolved boron in the spent fuel pit preserves the assumptions used in the analyses of the soluble boron credit, including the potential critical accident scenarios as described in Reference 1. This concentration of dissolved boron is necessary to control reactivity during fuel assembly storage and movement within the spent fuel pit.

BASES

APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the spent fuel pit until a complete spent fuel pit verification has been performed following the last movement of fuel assemblies in the spent fuel pit. This LCO does not apply following the verification since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.
ACTIONS	<u>A.1, A.2.1, and A.2.2</u> The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply. When the concentration of boron in the spent fuel pit is less than which is required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Alternatively, beginning a verification of the spent fuel pit fuel locations to ensure proper locations of the fuel can be performed. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position. If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, the inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.13.1</u> This SR verifies that the concentration of boron in the spent fuel pit is within the required limit. As long as this SR is met, the accidents mentioned are fully addressed. [The 7 day Frequency is appropriate because no major replenishment of pit water is expected to take place over such a short period of time. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]
REFERENCES	1. Section 9.1

B 3.7 PLANT SYSTEMS

B 3.7.14 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours).

Operating a unit at the allowable limits could result in a 2 hour EAB exposure of a small fraction of the 10 CFR 50.34 (Ref. 1) limits, or the limits established as the NRC staff approved licensing basis.

APPLICABLE SAFETY ANALYSES

The accident analysis of the steam system piping failure, as discussed in the Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of the steam system piping failure do not exceed a small fraction of the unit EAB limits (Ref. 1) for total effective dose equivalent.

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and the main steam relief valves (MSRVs). The Emergency Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

APPLICABLE SAFETY ANALYSES (continued)

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and MSRVs during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 1).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits 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 3.7.14.1 This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. [The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]
REFERENCES	1. 10 CFR 50.34. 2. Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.15 Main Steam Line Leakage

BASES

BACKGROUND	The purpose of the Main Steam Line Leakage LCO is to limit system operation in the presence of leakage from the main steam line inside containment to amounts that do not compromise safety consistent with the Leak-Before-Break (LBB) analysis discussed in Chapter 3, Section 3.6 (Ref. 1). This LCO specifies the amounts of leakage from the main steam line inside containment. LBB methodology allows elimination of postulated pipe breaks in certain piping systems based on the system characteristics and failure mechanics-based crack growth in conjunction with leak detection capability. As described in Section 3.6 (Ref. 1), the LBB concept is applied to the main steam piping inside containment. This LCO deals with protection of the main steam line inside containment from degradation and helps assure that serious leaks will not develop. The consequences of violating this LCO include the possibility of further degradation of the main steam lines, which may lead to pipe break.
APPLICABLE SAFETY ANALYSES	The safety analyses do not address the main steam line leakage. The safety significance of leakage inside containment varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring leakage into the containment area is necessary. The leakage detection instrumentations required by LCO 3.4.15 perform this function. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public. Although the main steam line leakage limit is not required by the 10 CFR 50.36(c)(2)(ii) criteria, this specification has been included in Technical Specifications because the LBB concept is applied to the main steam piping as well as RCL piping.
LCO	Main steam line leakage shall be limited to: 0.5 gallon per minute (gpm) including leakage from the main steam line inside containment is since it is below the leakage rate for LBB analyzed cases of a main steam line crack twice as long as a crack leaking at ten (10) times the detectable leak rate under normal operating load conditions. Violation of this LCO could result in continued degradation of the main steam line.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for main steam line leakage is greatest when the main steam line is pressurized.

In MODES 5 and 6, main steam line leakage limits are not required because the main steam line pressure is far lower, resulting in lower stresses and reduced potentials for main steam line leakage.

ACTIONS

A.1 and A.2

If main steam line leakage is not within limit, the unit 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 MODE 5 within 36 hours. This action reduces the main steam line leakage and also reduces the factors that tend to degrade the main steam line.

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. In MODE 5, the pressure stresses acting on the main steam line are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

Verifying main steam line leakage to be within the LCO limits ensures the integrity of the main steam line inside containment is maintained. Main steam line leakage would at first appear as unidentified LEAKAGE and can only be positively identified by inspection.

An early warning of main steam line leakage or unidentified LEAKAGE is provided by the automatic systems that monitor the level of containment sump used to collect unidentified LEAKAGE and air cooler condensate flow rate. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Also, by performance of an RCS water inventory balance, indication of containment environmental pressures, temperatures and radiation allow the determination of whether the main steam line is a potential source of unidentified LEAKAGE inside containment.

[The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES	1.	Chapter 3, Section 3.6 “Protection Against Dynamic Effects Associated with Postulated Rupture of Piping.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit Class 1E ac electrical power distribution system ac sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A, B, C, and D Class 1 E Gas Turbine Generators (GTGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the ac electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E ac distribution system is divided into redundant load groups (trains) so that the loss of any one or two groups does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single Class 1E GTG.

Offsite power is supplied to the unit switchyard(s) from the transmission network by two transmission lines. From the switchyard(s), two electrically and physically separated circuits provide ac power, through auxiliary transformers, to the Class 1E 6.9 kV buses. A detailed description of the offsite power network and the circuits to the Class 1E 6.9kV buses is found in Section8.2 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E 6.9kV bus(es).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E distribution system. Within 3 minutes after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

BASES

BACKGROUND (continued)

The onsite standby power source for each Class 1E 6.9 kV bus is a dedicated Class 1E GTG. A, B, C, and D Class 1E GTGs are dedicated to Class 1E 6.9kV buses , respectively. A Class 1E GTG starts automatically on an Emergency Core Cooling System (ECCS) actuation signal (i.e., low pressurizer pressure or high containment pressure signals) or on an Class 1E 6.9kV bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Gas Turbine Generator (GTG) Start Instrumentation"). After the Class 1E GTG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of Class 1E 6.9kV bus undervoltage or degraded voltage, independent of or coincident with an actuation signal. The Class 1E GTGs will also start and operate in the standby mode without tying to the Class 1E 6.9kV bus on an ECCS actuation signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the Class 1E 6.9kV bus. When the Class 1E GTG is tied to the Class 1E 6.9kV bus, loads are then sequentially connected to its respective Class 1E 6.9kV bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the Class 1E GTG by automatic load application.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the Class 1E GTGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of Postulated Accident (PA) such as a Loss of Coolant Accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the Class 1E GTG in the process. Within 3 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A, B, C, and D Class 1E GTGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each Class 1E GTG is 4500 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The Class 1E loads that are powered from the Class 1E 6.9 kV buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and PA analyses in Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The ac electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

APPLICABLE SAFETY ANALYSES (continued)

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 two trains of the onsite or offsite ac sources OPERABLE during accident conditions in the event of

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

b. A worst case single failure.

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

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E electrical power system and separate and independent Class 1E GTGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after AOO or PA.

Qualified offsite circuits are those that are described in Section 8.2 (Ref.2) and are part of the licensing basis for the unit.

In addition, one required automatic load sequencer per train must be OPERABLE.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Class 1E 6.9kV buses.

One of two circuits is through the unit auxiliary transformer, and the other circuit is from the reserve auxiliary transformer to each Class 1E 6.9kV bus. Normally Class 1E 6.9kV buses are supplied power from the reserve auxiliary transformer.

Each Class 1E GTG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective Class 1E 6.9kV bus on detection of bus undervoltage. This will be accomplished within 100 seconds. Each Class 1E GTG 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 Class 1E 6.9kV buses. These capabilities are required to be met from a variety of initial conditions such as Class 1E GTG in standby with the engine hot and GTG in standby with the engine at ambient conditions. Additional Class 1E GTG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the Class 1E GTG to revert to standby status on an ECCS actuation signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for Class 1E GTG OPERABILITY.

BASES

LCO (continued)

The ac sources in one train must be separate and independent (to the extent possible) of the ac sources in the other three trains. For the Class 1E GTGs, separation and independence are complete.

For the offsite ac sources, separation and independence are to the extent practical. A circuit may be connected to more than one Class 1E 6.9kV bus, with fast transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an Class 1E 6.9kV bus is required to have OPERABLE fast transfer interlock mechanisms to at least two Class 1E 6.9kV buses to support OPERABILITY of that circuit.

APPLICABILITY

The ac sources and sequencers 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 AOO or abnormal transients and

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

The ac power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable Class 1E GTG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable Class 1E GTG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

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

ACTIONS (continued)

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 Class 1E GTG 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. This includes motor driven emergency feedwater pumps. Two train systems, such as turbine driven emergency feedwater pumps, 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. One required train has no offsite power supplying it loads and

b. A required feature on the other train (Train A, B, C or D) is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked. Discovering no offsite power to one required 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, 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 circuit and Class 1E GTGs are adequate to supply electrical power to 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.

ACTIONS (continued)

A.3.1 [and A.3.2]

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in one required offsite circuit inoperable 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 Class 1E GTGs are adequate to supply electrical power to the onsite Class 1E distribution system.

[Required Action A.3.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

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 PA occurring during this period.

B.1

To ensure a highly reliable power source remains with an inoperable Class 1E GTG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that Class 1E GTGs in two trains are inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven emergency feedwater pumps. Two train systems, such as turbine driven emergency feedwater pumps, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable Class 1E GTG.

ACTIONS (continued)

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 Class 1E GTG exists and

b. A required feature on the other trains (Train A, B, C or D) is inoperable.

If at any time during the existence of this Condition (Class 1E GTGs in two trains inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering required Class 1E GTGs in two trains inoperable coincident with two or more inoperable required support or supported features, or both, that are associated with the OPERABLE Class 1E GTG, 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 Class 1E GTG and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution systems. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining ac sources, a reasonable time for repairs, and the low probability of PA occurring during this period.

ACTIONS (continued)

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE Class 1E GTG(s). If it can be determined that the cause of the inoperable Class 1E GTG does not exist on the OPERABLE Class 1E GTG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other Class 1E GTG(s), the other Class 1E GTG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable Class 1E GTG cannot be confirmed not to exist on the remaining Class 1E GTG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that Class 1E GTG.

In the event the inoperable Class 1E GTG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE Class 1E GTGs are not affected by the same problem as the inoperable Class 1E GTGs.

B.4.1 [and B.4.2]

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

[Required Action B.4.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

In Condition B, the remaining OPERABLE Class 1E GTG and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution systems. 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 PA occurring during this period.

C.1, C.2.1 [and C.2.2]

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions.

ACTIONS (continued)

The Class 1E GTGs are adequate to supply electrical power to the onsite Class 1E Distribution System. The 12 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, 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. Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that safety trains are completely 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.

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

a. All required offsite circuits are inoperable and

b. A required feature is inoperable.

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

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

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two ac sources inoperable that involve one or more Class 1E GTGs 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.

ACTIONS (continued)

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

According to 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 restored within 24 hours, power operation continues in accordance with Condition A. The Class 1E GTGs connect to Class 1E buses when other all ac power sources are unavailable, until one required offsite circuit is restored to OPERABLE status. COMPRETION TIME of subsequent CONDITION is limited by maximum COMPLETION TIME in accordance with administrative control.

[Required Action C.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

ACTIONS (continued)

D.1, D.2 [and D.3]

Pursuant to LCO 3.0.6, the distribution system ACTIONS would not be entered even if all ac sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no ac source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one or two Class 1E GTG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

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

[Required Action D.3 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

E.1

With three or four Class 1E GTGs inoperable, there is only one or no remaining standby ac sources. 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 very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of ac power). Since any inadvertent generator trip could also result in a total loss of offsite ac power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

ACTIONS (continued)

According to Reference 6, with three of four Class 1E GTGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 [and F.2]

The sequencer(s) is an essential support system to both the offsite circuit and the Class 1E GTG associated with a given Class 1E 6.9kV bus. Furthermore, the sequencer is on the primary success path for most major ac electrically powered safety systems powered from the associated Class 1E 6.9kV bus. Therefore, loss of a Class 1E 6.9kV bus sequencer affects every major Class 1E 6.9kV system in the affected train. The 12 hour Completion Time for Required Action F.1 provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

[Required Action F.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

G.1 and G.2

If the inoperable ac electric power sources 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 6 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 plant systems.

H.1

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

SURVEILLANCE REQUIREMENTS

The ac sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the Class 1E GTGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 9).

The performance frequency of the US-APWR Class 1 E GTG refueling cycle surveillance tests SR 3.8.1.8 through SR 3.8.1.18 is 24 months compared 18 months for STS NUREG-1431 DG surveillance tests SR 3.8.1.7 and SR 3.8.1.9 through SR 3.8.1.19. These SRs should be performed after GTG's maintenance, typically during a refueling outage, because GTG capability should be checked after GTG maintenance. Also, performance of these SRs, during normal plant operation, or any plant condition, other than a shutdown, or during a refueling outage, could cause perturbation to the safety systems, or could remove a required offsite power circuit, or a Class 1E GTG from service, as described in the NOTE(S) of each applicable SR (3.8.1.8 through 3.8.1.13 and 3.8.1-15 through 3.8.1.18). SR 3.8.1.14 does not contain the NOTE, but it is a similar situation, because it is usual practice for SR 3.8.1.14 to be performed following SR 3.8.1.13.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 6762 V is 98% of the nominal 6900 V output voltage. This value allows for voltage drop to the terminals of 460 V motors whose minimum transient voltage is specified as 75% (Ref. 2). The specified maximum steady state output voltage of 7038 V ensures that for a lightly loaded distribution system, the voltage at the terminals of 6600 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the Class 1E GTG are 59.4 Hz and 60.6 Hz, respectively. These values are equal to ± 1% of the 60 Hz nominal frequency and are based on the assumed frequency for operation of SI pumps.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite ac electrical power supply to the onsite distribution network and availability of offsite ac electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. [The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate AOO and PA and to maintain the unit in a safe shutdown condition.

For the purposes of SR 3.8.1.2 testing, the Class 1E GTGs are started from standby conditions.

SR 3.8.1.2 requires that the Class 1E GTG starts from standby conditions and achieves required voltage and frequency within 100 seconds. The 100 second start requirement supports the assumptions of the design basis LOCA analysis in Chapter 15 (Ref. 5).

In addition to the SR requirements, the time for the Class 1E GTG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

[The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of Class 1E GTG OPERABILITY, while minimizing degradation resulting from testing. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the Class 1E GTGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the Class 1E GTG is connected to the offsite source.

Although no power factor requirements are established by this SR, the Class 1E GTG 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 the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the Class 1E GTG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain Class 1E GTG OPERABILITY.

[The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by four Notes. Note 1 indicates that Class 1E GTG runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the Class 1E GTG are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one Class 1E GTG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful Class 1E GTG start must precede this test to credit satisfactory performance.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of Class 1E GTG 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 facility operators would be aware of any large uses of fuel oil during this period. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks 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 Class 1E GTG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. [The Surveillance Frequency of 31 days is established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventative maintenance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

[The Frequency for this SR is variable, depending on individual system design, with up to a 92 day interval. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Code (Ref. 10); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following Class 1E GTG testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of Class 1E GTG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.1.7

Transfer of each Class 1E 6.9 kV 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. Switching function of the breakers will not be degraded within 24 months based on appropriate maintenance of the breaker. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following

SURVEILLANCE REQUIREMENTS (continued)

corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system

when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.8

Each Class 1E GTG 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 engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the Class 1E GTG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. This Surveillance may be accomplished by:

a. Tripping the Class 1E GTG output breaker with the Class 1E GTG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus, or

b. Tripping its associated single largest post-accident load with the Class 1E GTG solely supplying the bus.

As required by IEEE-308 (Ref. 11), the load rejection test is acceptable if the increase in Class 1E GTG 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 time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated withsequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the Class 1E GTG. SR 3.8.1.8.a corresponds to the maximum frequency

BASES

SURVEILLANCE REQUIREMENTS (continued)

excursion, while SR 3.8.1.8.b and SR 3.8.1.8.c are steady state voltage and frequency values to which the system must recover following load rejection. [The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

Note 2 ensures that the Class 1E GTG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.9. This power factor should be maintained as close as practicable to actual power factor which a Class 1E GTG would see under design basis accident conditions, such as 0.85. Under certain conditions, however, Note 2 allows the Surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the Class 1E GTG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the Class 1E GTG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding the Class 1E GTG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

This Surveillance demonstrates the Class 1E GTG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The Class 1E GTG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the Class 1E GTG experiences following a full load rejection and verifies that the Class 1E GTG does not trip upon loss of the load. These acceptance criteria provide for Class 1E GTG damage protection. While the Class 1E GTG is not expected to experience this transient during an event and continues to be available, this response ensures that the Class 1E GTG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Credit may be taken for unplanned events that satisfy this SR. Note 2 ensures that the Class 1E GTG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.9. This power factor should be maintained as close as practicable to actual power factor which a Class 1E GTG would see under design basis accident conditions, such as 0.85. Under certain conditions, however, Note 2 allows the Surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the Class 1E GTG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the Class 1E GTG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding the Class 1E GTG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the Class 1E GTG. It further demonstrates the capability of the Class 1E GTG to automatically achieve the required voltage and frequency within the specified time.

The Class 1E GTG autostart time of 100 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The Class 1E GTG autostart time of 100 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the Class 1E GTG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Safety Injection System (SIS) injection valves are not desired to be stroked open, or safety injection systems are not capable of being

operated at full flow. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the Class 1E GTG systems 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

This Surveillance demonstrates that the Class 1E GTG automatically starts and achieves the required voltage and frequency within the specified time (100 seconds) from the design basis actuation signal (ECCS actuation signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.11.d and SR 3.8.1.11.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS actuation signal without loss of offsite power.

The requirement to verify the connection of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the Class 1E GTG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, SIS injection valves are not desired to be stroked open, or safety injection systems are not capable of being operated at full flow. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the Class 1E GTG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

This Surveillance demonstrates that Class 1E GTG noncritical protective functions) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. Noncritical automatic trips are all automatic trips except:

a. Overspeed;

b. Generator differential current;

c. High exhaust temperature; and

d. Fail to start.

The noncritical trips are bypassed during PA and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The Class 1E GTG availability to mitigate the PA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the Class 1E GTG.

SURVEILLANCE REQUIREMENTS (continued)

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required Class 1E GTG from service. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

Regulatory Guide 1.9 (Ref. 3), requires demonstration that the Class 1E GTGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the Class 1E GTG. The Class 1E GTG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the Class 1E GTG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain Class 1E GTG OPERABILITY.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Note 3 ensures that the Class 1E GTG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.9. This power factor should be maintained as close as practicable to actual power factor which a Class 1E GTG would see under design basis accident conditions, such as 0.85. Under certain conditions, however, Note 3 allows the Surveillance to be conducted as a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the Class 1E GTG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the Class 1E GTG. In such cases, the power factor shall be maintained close as practicable to 0.9 without exceeding the Class 1E GTG excitation limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

This Surveillance demonstrates that the Class 1E GTG can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 100 seconds. The 100 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The Note ensures that the test is performed with the Class 1E GTG sufficiently hot. The load band is provided to avoid routine overloading of the Class 1E GTG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain Class 1E GTG OPERABILITY. The requirement that the Class 1E GTG has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test.

SR 3.8.1.15

As required by Regulatory Guide 1.9 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the Class 1E GTG to the offsite source can be made and the Class 1E GTG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the Class 1E GTG to reload if a subsequent loss of offsite power occurs. The Class 1E GTG is considered to be in ready to load status when the Class 1E GTG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

Demonstration of the test mode override ensures that the Class 1E GTG availability under accident conditions will not be compromised as the result of testing and the Class 1E GTG will automatically reset to ready to load operation if an ECCS actuation signal is received during operation in the test mode. Ready to load operation is defined as the Class 1E GTG running at rated speed and voltage with the Class 1E GTG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 11), paragraph 5.2.4.6(b).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.11. The intent in the requirement associated with SR 3.8.1.16.b is to show that the emergency loading was not affected by the Class 1E GTG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Under accident and loss of offsite power conditions loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the Class 1E GTGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the Class 1E GTG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of Class 1E 6.9kV buses.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

In the event of PA coincident with a loss of offsite power, the Class 1E GTGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the Class 1E GTG operation, as discussed in the Bases for SR 3.8.1.10, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the Class 1E GTG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

[The 24 month Frequency of this SR is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance and the demonstrated reliability of the US-APWR Class 1E GTG, and is intended to be consistent with the expected fuel cycle length. Reliability of the US-APWR Class 1E GTG is based on the qualification testing of the prototype GTG, as documented in Technical Report MUAP-10023. It is also based on operating experience of GTGs in nonnuclear applications, as documented in Technical Report MUAP-07024, which have longer surveillance test intervals, and less frequent equivalent surveillances for Class 1E emergency diesel generators at operating nuclear plants. The more frequent performance of these surveillances for US-APWR Class 1E GTGs enhances the Class 1E GTG reliability compared to GTGs in nonnuclear applications. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The 24 month Frequency is also consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

<u>SR 3.8.1.19</u>

This Surveillance demonstrates that the Class 1E GTG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the Class 1E GTGs are started simultaneously.

[The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance performs cleaning of the two fuel nozzles on each Class 1E gas turbine generator. Each Class 1E gas turbine generator has two engines. Each engine has an attached combustion chamber. The fuel nozzle supplies fuel oil to the combustion chamber. There is a nozzle tip in the end of the fuel nozzle which atomizes and sprays the liquid fuel. The nozzle tip gets clogged as the number of gas turbine generator starts and stops increases. This is because the liquid fuel that remains in the nozzle tip is carbonized by heat from hot parts such as the combustion chamber, which remains hot for a while after the engine stops. Clogging of the nozzle tip causes abnormal fuel atomization and could cause failure of the gas turbine generator to start. This cleaning was performed during the Class 1E gas turbine generator qualification testing.

The Frequency of this Surveillance is once per 50 gas turbine generator starts as this Frequency of nozzle cleaning was used during the Class 1E gas turbine generator qualification per the manufacturer's recommendation. This manufacturer's recommendation was based on typical industrial experience including the use of lower quality fuel (e.g., A-type heavy oil) than is used for the Class 1E gas turbine generators.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. Section 8.2.

3. Regulatory Guide 1.9, Rev. 4, March 2007.

4. Chapter 6.

5. Chapter 15.

6. Regulatory Guide 1.93, Rev. 0, December 1974.

7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

8. 10 CFR 50, Appendix A, GDC 18.

9. Regulatory Guide 1.137, Rev.1, October 1979.

10. ASME Code for Operation and Maintenance of Nuclear Power Plants.

11. IEEE 308-2001.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND

A description of the ac sources is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum ac sources during MODES 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.

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 Postulated Accident (PA) 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 PA 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 MODE 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 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 Class 1E Gas Turbine Generator (GTGs) power.

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

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. OPERABLE Class 1E GTGs, associated with distribution systems trains required to be OPERABLE by LCO 3.8.10, ensure 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(s) and Class 1E GTGs 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 Class 1E bus(es). Qualified offsite circuits are those that are described in Section 8.2 (Ref. 1) and are part of the licensing basis for the unit.

One of two circuits is through the unit auxiliary transformer, and the other circuit is from the reserve auxiliary transformer to each Class 1E bus. Normally Class 1E 6.9kV buses are supplied power from the reserve auxiliary transformer.

BASES

LCO (continued)

The Class 1E GTGs must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective Class 1E on detection of bus undervoltage. This sequence must be accomplished within 100 seconds. The Class 1E GTGs must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the Class 1E buses. These capabilities are required to be met from a variety of initial conditions such as Class 1E GTG in standby with the engine hot and Class 1E GTG in standby at ambient conditions.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for Class 1E GTG OPERABILITY.

In addition, proper sequencer operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts on the ability to start and maintain energized loads required OPERABLE by LCO 3.8.10.

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 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 or refueling condition.

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

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 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 MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

BASES

ACTIONS (continued)

A.1

Although two trains are required by LCO 3.8.10, the two trains with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and irradiated 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 Class 1E GTG(s) 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 that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron

concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the distribution system's ACTIONS would not be entered even if all ac sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no ac power to any required Class 1E 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. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the ac sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.7 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.11 and SR 3.8.1.18 are not required to be met because the ESF actuation signal is not required to be OPERABLE. SR 3.8.1.16 is not required to be met because the required OPERABLE Class 1E GTG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.19 is excepted because starting independence is not required with the Class 1E GTG(s) that is not required to be operable.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE Class 1E GTG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required Class 1E 6.9 kV 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 Class 1E GTGs. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the Class 1E GTGs and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

1. Section 8.2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Class 1E Gas Turbine Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each Class 1E Gas Turbine Generator (GTG) is provided with a storage tank having a fuel oil capacity sufficient to operate that gas turbine for a period of 7 days while the Class 1E GTG is supplying maximum post loss of coolant accident load demand discussed in Subsection 9.5.4 (Ref. 1). The maximum load demand is calculated using the assumption that a minimum of any four Class 1E GTGs is available. This onsite fuel oil capacity is sufficient to operate the Class 1E GTGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from the storage tank to the day tank by either of two transfer pumps associated with each storage tank.

For proper operation of the standby Class 1E GTGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The Class 1E GTG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated Class 1E GTG under all loading conditions. The system is required to circulate the lube oil to the gas turbine engine working surfaces and to remove excess heat generated by friction during operation. The engine oil sump in each Class 1E GTG gear boxes contains an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each Class 1E GTG has an air start system with adequate capacity for three successive start attempts on the Class 1E GTG without recharging the air start receiver(s).

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 4), and in Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The Class 1E GTGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Since gas turbine fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored gas turbine fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of Class 1E GTGs required to shut down the reactor and to maintain it in a safe condition for AOO or PA with loss of offsite power. Class 1E GTG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for three successive Class 1E GTG start attempts without recharging the air start receivers.

APPLICABILITY

The ac sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after AOO or PA. Since stored gas turbine fuel oil, lube oil, and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored Class 1E GTG fuel oil, lube oil, and starting air are required to be within limits when the associated Class 1E GTG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each Class 1E GTG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable Class 1E GTG subsystem. Complying with the Required Actions for one inoperable Class 1E GTG subsystem may allow for continued operation, and subsequent inoperable Class 1E GTG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

BASES

ACTIONS (continued)

A.1

In this Condition, the 7 day fuel oil supply for a Class 1E GTG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the Class 1E GTG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period. Fuel oil storage tank inventory is controlled to restore following any operation of a gas turbine, including maintenance and testing runs by administrative control.

B.1

With lube oil inventory < 81 gallons, sufficient lubricating oil to support 7 days of continuous Class 1E GTG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the Class 1E GTG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

BASES

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.5. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the gas turbine engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated Class 1E GTG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the Class 1E GTG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.4 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a Class 1E GTG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the Class 1E GTG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < 398 psig, sufficient capacity for three successive Class 1E GTG start attempts does not exist. However, as long as the receiver pressure is > 228 psig, there is adequate capacity for at least one start attempt, and the Class 1E GTG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the Class 1E GTG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most Class 1E GTG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

BASES

ACTIONS (continued)

F.1

With a Required Action and associated Completion Time not met, or one or more Class 1E GTG's fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated Class 1E GTG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each Class 1E GTG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

[The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each Class 1E GTG. The 81 gallons requirement is based on the Class 1E GTG manufacturer consumption values for the run time of the Class 1E GTG.

[A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since Class 1E GTG starts and run time are closely monitored by the unit staff. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on gas turbine engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the

BASES

SURVEILLANCE REQUIREMENTS (continued)

entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-06 (Ref. 6),

b. Verify in accordance with the tests specified in ASTM D975-07b (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 39° when tested in accordance with ASTM D1298-99 (Reapproved 2005) (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F, and

c. Verify that the new fuel oil has a water and sediment content within limits when tested in accordance with ASTM D2709-96(Reapproved 2006)(Ref. 6).

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

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-07b (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-07b (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-03, ASTM D2622-07, or ASTM D4294-03 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on GTG operation. This Surveillance ensures the availability of high quality fuel oil for the GTGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a gas turbine engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D5452-06 (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each Class 1E GTG is available. The system design requirements provide for a minimum of three engine start cycles without recharging. A start cycle is defined by the Class 1E GTG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the three starts can be accomplished.

[The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks 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 Class 1E GTG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. [The Surveillance Frequencies of 31 days are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES

1. Subsection 9.5.4.

2. Regulatory Guide 1.137. Rev.1, October 1979.

3. ANSI N195-1976, Appendix B.

4. Chapter 6.

5. Chapter 15.

6. ASTM Standards: D4057-06; D975-07b; D1298-99 (Reapproved 2005); D2709-96 (Reapproved 2006); D1552-03; D2622-07; D4294-03; D5452-06.

7. ASTM Standards, D975-07b, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station dc electrical power system provides the ac emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred ac vital bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the dc electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The dc electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 Vdc electrical power system consists of four independent and redundant safety related Class 1E dc electrical power subsystems (Trains A, B, C, and D). Each subsystem consists of one 125 Vdc battery, the associated battery charger for each battery, and all the associated control equipment and interconnecting cabling.

Additionally there are two spare battery chargers, which provide backup service in the event that the preferred battery charger is out of service. If the spare battery charger is substituted for one of the preferred battery chargers, then the requirements of independence and redundancy between subsystems are maintained.

During normal operation, the 125 Vdc load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the dc load is automatically powered from the station batteries.

The Train A, B, C, and D dc electrical power subsystems provide the control power for its associated Class 1E ac power load group, 6.9 kV switchgear, and 480 V load centers. The dc electrical power subsystems also provide dc electrical power to the inverters, which in turn power the ac vital buses.

The dc power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each 125 Vdc battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

BACKGROUND (continued)

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in Subsection 8.3.2 (Ref 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train A, B, C, and D dc electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limit is 108 V.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 125 V for a 60 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.17 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.07 Vpc corresponds to a total float voltage output of 124.2 V for a 60 cell battery.

Each Train A, B, C, and D dc electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in Subsection 8.3.2 (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

The Class 1E Electrical Room HVAC System is a support system and provides temperature control and battery room exhaust for the Class 1E Battery and Battery Charger Rooms where the dc electrical power subsystems are located. The system includes electric heating coils, chilled water cooling coils, fans, filters, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller.

BASES

BACKGROUND (continued)

The Class 1E Electrical Room HVAC System consists of four redundant trains, each sized to satisfy 100% of the cooling and heating demand of two Class 1E Battery and Battery Charger Rooms. Class 1E Electrical Room HVAC train A or B can provide cooling and heating for both A and B Class 1E Battery and Battery Charger Rooms, and train C or D can provide cooling and heating for both C and D Class 1E Battery and Battery Charger Rooms. For each dc electrical power subsystem train required to be OPERABLE, one of the associated Class 1E Electrical Room HVAC System trains, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, and capable of performing its related support function.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 5) and Chapter 15 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The dc electrical power systems provide normal and emergency dc electrical power for the Class 1E GTGs, emergency auxiliaries, and control and switching during all MODES of operation.

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

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

b. A worst-case single failure.

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

LCO

The dc electrical power subsystems, each subsystem consisting of one battery, battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated bus. This LCO requires three trains to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after AOO or PA. Loss of any train dc electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE dc electrical power subsystem requires the battery and its respective charger to be operating and connected to the associated dc bus.

APPLICABILITY

The dc electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

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

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of PA.

The dc electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

BASES

ACTIONS

A.1, A.2, [and A.3]

Condition A represents two trains with battery chargers inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability. The minimum established float voltage will be selected from manufacturer's recommendation float voltage range and controlled by administrative control.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the dc system is designed for.

BASES

ACTIONS (continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated dc system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to [5] amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 24 hour period the battery float current is not less than or equal to [5] amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3.1 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). [Required Action A.3.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.] The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

<u>B.1</u>

Condition B represents batteries in two trains inoperable. With the batteries in these two trains inoperable, the associated dc buses are being supplied by their OPERABLE battery chargers. Any event that results in a loss of the ac buses supporting the battery chargers will also result in loss of dc to those trains. Recovery of the ac bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., Class 1E GTG control and field flash, ac load shed and Class 1E GTG output circuit breakers, etc.) likely rely upon the battery. In addition the energization transients of any dc loads that are beyond the capability of the battery charger and normally require the assistance of the battery will not be able to be brought online. The 2 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific Completion Times.

BASES

ACTIONS (continued)

C.1

Condition C represents two trains with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of dc power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable dc distribution system in two trains.

If one of the required dc electrical power subsystems is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger and associated inoperable battery), the remaining dc electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst- case single failure could, however, result in the loss of minimum necessary dc electrical subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable dc electrical power subsystem and, if the dc electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

D.1 and D.2

If the inoperable dc electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 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 plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated dc subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.17 Vpc or 130.2 V at the battery terminals). This voltage is controlled by administrative control. This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). [The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 8). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 700 amps at the minimum established float voltage for 8 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of ac power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional

SURVEILLANCE REQUIREMENTS (continued)

loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ [5] amps.

[The 24 month Frequency of this SR 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. The battery chargers are static equipment, thus significant degradation due to a longer surveillance interval should not be major concern. Furthermore, the battery charger operates constantly to charge the battery and supply to load. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

<u>SR 3.8.4.3</u>

A battery service test is a special test of the battery capability, as found, to satisfy the design requirements (battery duty cycle) of the dc electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

[The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations, or at some other outage, with intervals between tests not to exceed 24 months. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, Rev.0, March 1971.
3. IEEE-308-2001.
4. Subsection 8.3.2.
5. Chapter 6.
6. Chapter 15.
7. Regulatory Guide 1.93, Rev.0, December 1974.
8. IEEE-450-2002.
9. Regulatory Guide 1.32, Rev.3, March 2004.
10. Regulatory Guide 1.129, Rev.2, February 2007.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the dc sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The dc electrical power system provides normal and emergency dc electrical power for the Class 1E Gas Turbine Generators (GTGs), emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the dc subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum dc electrical power 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 dc electrical power is provided to mitigate events postulated during shutdown.

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 PA that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses 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 PA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case PA which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

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

LCO

The dc electrical power is made up of subsystems. Each subsystem consists of one battery, one battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train. A subsystem is required to be OPERABLE to support the associated required trains of the distribution systems specified by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient dc electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The dc electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core,

b. Required features needed to mitigate a fuel handling accident are available,

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and

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

BASES

APPLICABILITY (continued)

The dc electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4, “DC Sources – Operating”.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 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 MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

<u>A.1, A.2, and A.3</u>

Condition A represents one required train with one battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk.

ACTIONS (continued)

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the dc system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated dc system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to [5] amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 24 hour period the battery float current is not less than or equal to [5] amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

BASES

ACTIONS (continued)

B.1, B.2.1, B.2.2, B.2.3, and B.2.4

If two trains are required by LCO 3.8.10, “Distribution Systems – Shutdown”) the remaining train with dc power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and irradiated fuel movement. By allowing the option to declare required features inoperable with the associated dc power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO 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) that could result in loss of required SDM (MODE 5) or boron concentration

(MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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

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

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE dc sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. Chapter 6.

2. Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the dc power subsystem batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown." In addition to the limitations of this Specification, the licensee controlled program also implements a program specified in Specification 5.5.17 for monitoring various battery parameters that is based on the recommendations of IEEE-450(Ref. 1).

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 125 V for 60 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.17 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.07 Vpc corresponds to a total float voltage output of 124.2 V for a 60 cell battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 3) and Chapter 15 (Ref. 4), assume Engineered Safety Feature systems are OPERABLE. The dc electrical power system provides normal and emergency dc electrical power for the Class 1E Gas Turbine Generators (GTGs), emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the dc subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of dc sources OPERABLE during accident conditions, in the event of:

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

b. A worst-case single failure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required dc power to shut down the reactor and maintain it in a safe condition after Anticipated Operational Occurrence (AOO) or PA. Battery parameter limits are conservatively established, allowing continued dc electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the licensee controlled program is conducted as specified in Specification 5.5.17.

APPLICABILITY

The battery parameters are required solely for the support of the associated dc electrical power subsystems. Therefore, battery parameter limits are only required when the dc power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one battery in one train < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one battery < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

BASES

ACTIONS (continued)

B.1 and B.2

One battery in one train with float current > [5] amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addresses charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated dc system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 24 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 V, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 V there is good assurance that, within 24 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 24 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 24 hours is a reasonable time prior to declaring the battery inoperable.

BASES

ACTIONS (continued)

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

C.1, C.2, and C.3

With one battery in one train with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established. The minimum established design limits are determined based on manufacturer's recommendation and controlled by administrative control.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.17, Battery Monitoring and Maintenance Program). They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.17.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE-450. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries in one train with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met. The minimum established design limits are determined based on manufacturer's recommendation and controlled by administrative control.

BASES

ACTIONS (continued)

E.1

With one or more batteries in redundant trains with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one train within 2 hours. The battery parameters limits are determined based on manufacturer's recommendation and controlled by administrative control.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one train with one or more battery cells float voltage less than 2.07 V and float current greater than [5] amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 1). [The 7 day Frequency is consistent with IEEE-450 (Ref. 1). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTIONS A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of [5] amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 135 V at the battery terminals, or 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.17. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V. [The Frequency for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell is consistent with IEEE-450 (Ref. 1). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.8.6.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. [The Frequency of 31 days is consistent with IEEE-450 (Ref. 1). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The minimum established design limits are determined based on manufacturer's recommendation and controlled by administrative control.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 40°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. [The Frequency is consistent with IEEE-450 (Ref. 1). OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The minimum established design limits are determined based on manufacturer's recommendation and controlled by administrative control.

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. This test is implemented in accordance with IEEE-450 (Ref. 1)

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

It may consist of just two rates; for instance the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit. Manufacturer’s rating of the battery capacity for an acceptance criterion is determined based on manufacturer’s recommendation and controlled by administrative control.

[The Surveillance Frequency for this test is normally 60 months. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced [to 12 months. OR in accordance with the Surveillance Frequency Control Program.] However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is [only] reduced [to 24 months OR in accordance with the Surveillance Frequency Control Program.] for batteries that retain capacity ≥ 100% of the manufacturer's ratings. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1). Battery expected life for setting the performance FREQUENCY is determined based on manufacturer’s recommendation and controlled by administrative control.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes.

BASES

SURVEILLANCE REQUIREMENTS (continued)

These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. IEEE-450-2002.

2. Chapter 8.

3. Chapter 6.

4. Chapter 15.

5. IEEE-485-1997.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the ac vital buses because of the stability and reliability they achieve. The function of the inverter is to provide ac electrical power to the vital buses. The inverters can be powered from an internal ac source/rectifier or from the station battery. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in Subsection 8.3.1 (Ref. 1).

The Class 1E Electrical Room HVAC System is a support system and provides temperature control for the Class 1E UPS Rooms where the inverters are located. The system includes electric heating coils, chilled water cooling coils, fans, filters, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller.

The Class 1E Electrical Room HVAC System consists of four redundant trains, each sized to satisfy 100% of the cooling and heating demand of two Class 1E UPS Rooms. Class 1E Electrical Room HVAC train A or B can provide cooling and heating for both A and B Class 1E UPS Rooms, and train C or D can provide cooling and heating for both C and D Class 1E UPS Rooms. For each inverter required to be OPERABLE, one of the associated Class 1E Electrical Room HVAC System trains, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, and capable of performing its related support function.

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required ac vital buses OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of ac electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after AOO or PA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The inverters ensure an uninterruptible supply of ac electrical power to the required ac vital buses even if the Class 1E 6.9 kV safety buses are de-energized.

BASES

LCO (continued)

OPERABLE inverters require the associated vital bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 Vdc station battery. Alternatively, power supply may be from an internal ac source via rectifier as long as the station battery is available as the uninterruptible power supply.

This LCO is modified by a Note that allows one inverter to be disconnected from a battery for ≤ 24 hours, if the vital bus is powered from a Class 1E transformer during the period and all other inverters are OPERABLE. This allows an equalizing charge to be placed on one battery bank. If the inverter was not disconnected, the resulting voltage condition might damage the inverter. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected ac vital bus while taking into consideration the time required to perform an equalizing charge on the battery bank.

The intent of this Note is to limit the number of inverters that may be disconnected. Only the inverter associated with the single battery undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries.

APPLICABILITY

The inverters 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.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

<u>A.1 [and A.2]</u>

With a required inverter inoperable, its associated ac vital bus becomes inoperable until it is re-energized from its Class 1E transformer.

BASES

ACTIONS (continued)

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.] The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the ac vital bus is powered from its transformer, it is relying upon interruptible ac electrical power sources (offsite and onsite). The uninterruptible inverter source to the ac vital buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

If the inoperable devices or components 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 6 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and ac vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the ac vital buses. The proper voltage and frequency of inverter and breaker alignment are controlled by administrative control. [The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

REFERENCES	1.	Subsection 8.3.1.
	2.	Chapter 6.
	3.	Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters - Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The dc to ac inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each ac vital bus during MODES 5 and 6 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

Adequate power is available to mitigate events postulated during shutdown.

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 PA that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses 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 PA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case PA which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The battery powered inverters provide uninterruptible supply of ac electrical power to the ac vital buses even if the normal power from the 480Vac safety buses are de-energized. OPERABILITY of the inverters requires that the ac vital bus be powered by the inverter. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown).

APPLICABILITY

The inverters 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 or refueling condition.

APPLICABILITY (continued)

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7, “Inverters - Operating.”

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 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 MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

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

If two trains are required by LCO 3.8.10, "Distribution Systems - Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, irradiated fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' 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) that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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 inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

BASES

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and ac vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the ac vital buses. The proper voltage and frequency of inverter and breaker alignment are controlled by administrative control. [The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Chapter 6.

2. Chapter 15.

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 by train into four redundant and independent ac, dc, and ac vital bus electrical power distribution subsystems (Trains A, B, C, and D).

The ac electrical power subsystem for each train consists of a Class 1E 6.9 kV bus and secondary buses, motor control centers and load centers. Each 6.9 kV bus has at least two separate and independent offsite sources of power as well as a dedicated onsite Class 1E Gas Turbine Generator (GTG) source. Each Class 1E 6.9 kV bus is normally connected to a preferred offsite source. After a loss of the preferred offsite power source to a Class 1E 6.9 kV bus, a transfer to the alternate offsite source is accomplished by utilizing a time delayed bus undervoltage relay. If all offsite sources are unavailable, the onsite Class 1E GTG supplies power to the 6.9 kV bus. Control power for the 6.9 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

This LCO supports On Line Maintenance (OLM) of Class 1E GTGs. Therefore, only three ac distribution trains are generally required to be OPERABLE. To support OLM on A Train or D Train, lower voltage ac and dc switchgear on the affected train that are required to be OPERABLE at all times (i.e., A1 and D1 480V LC, and A1 and D1 dc Switchboards) will be cross-tied to their associated train with an OPERABLE Class 1E GTG. These A Train and D Train secondary ac and dc subsystems are normally powered from their respective trains.

The secondary ac electrical power distribution subsystem for each train includes the safety related buses, load centers, and motor control centers shown in Table B 3.8.9-1.

The 120 Vac vital buses are arranged in one load group per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters - Operating." Each transformer is powered from a Class 1E ac bus.

The dc electrical power distribution subsystem consists of four 125 V buses and distribution panels.

BASES

BACKGROUND (continued)

The list of all required dc and vital ac distribution buses are presented in Table B 3.8.9-1. Specific details on inverters and their operating characteristics are found in Chapter 8 (Ref. 4).

The Class 1E Electrical Room HVAC System is a support system and provides temperature control for the Class 1E Electrical Rooms where the ac, dc, and ac vital bus electrical power distribution subsystems are located. The system includes electric heating coils, chilled water cooling coils, fans, filters, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller.

The Class 1E Electrical Room HVAC System consists of four redundant trains, each sized to satisfy 100% of the cooling and heating demand of two Class 1E Electrical Rooms. Class 1E Electrical Room HVAC train A or B can provide cooling and heating for both A and B Class 1E Electrical Rooms, and train C or D can provide cooling and heating for both C and D Class 1E Electrical Rooms. For each ac, dc, and ac vital bus electrical power distribution subsystem train required to be OPERABLE, one of the associated Class 1E Electrical Room HVAC System trains, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, and capable of performing its related support function.

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 1), and in Chapter 15 (Ref. 2), assume Engineered Safety Features (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, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

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

LCO

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

Maintaining the required ac, dc, and ac vital bus electrical power distribution subsystems OPERABLE per Table 3.8.9-1, 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, and motor control centers to be energized to their proper voltages. OPERABLE dc electrical power distribution subsystems require the associated buses and distribution panels to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter or Class 1E transformer.

BASES

LCO (continued)

This LCO is modified by Notes. Note 2 permits the two train buses to be removed from operation when switching from one train to another. The circumstances for de-energizing two train buses are to be limited to situations when the outage time is short.

APPLICABILITY

The electrical power 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 PA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."

ACTIONS

<u>A.1 [and A.2]</u>

With one Train A, B, C or D required ac bus, load center, or motor control center inoperable and a loss of function has not 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, and motor control centers must be restored to OPERABLE status within 8 hours. [Required Action A.2 allows the option to apply the requirements of Specification 5.5.18 to determine a Risk Informed Completion Time (RICT). This Requied Action is not applicable in MODE 4.]

Condition A worst scenario is one required train without ac power (i.e., no offsite power to the train and the associated GTGs 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 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

BASES

ACTIONS (continued)

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.

Required Action A.1 is modified by a Note that requires the applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," to be entered for dc trains made inoperable by inoperable power distribution subsystems. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. Inoperability of a distribution system can result in loss of charging power to batteries and eventual loss of dc power. This Note ensures that the appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

B.1

With one ac vital bus 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 required ac vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted dc or Class 1E transformer.

Condition B represents one required ac vital bus without power; potentially both the dc sources and the associated ac sources are nonfunctioning. 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 2 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, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

ACTIONS (continued)

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 2 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 PA occurring during this period.

C.1

With one required dc bus or distribution panel inoperable, and a loss of function has not yet occurred, the remaining dc electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining dc electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required dc buses and distribution panels must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one required dc bus or distribution panel 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 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate dc power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

ACTIONS (continued)

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 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 2 hour Completion Time for dc buses is consistent with Regulatory Guide 1.93 (Ref. 3).

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 6 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 plant systems.

E.1

Condition E corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one required 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. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required 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 loads connected to these buses. [The 7 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. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Chapter 6.
2. Chapter 15.
3. Regulatory Guide 1.93, Rev.0, December 1974.
4. Chapter 8.

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

TYPE	VOLTAGE	TRAIN A*	TRAIN B*	TRAIN C*	TRAIN D*
AC safety buses	6900 V	Class 1E Bus A	Class 1E Bus B	Class 1E Bus C	Class 1E Bus D
AC Load Centers	480 V	Load Centers A A1$^{(1)}$	Load Center B	Load Center C	Load Centers D D1$^{(2)}$
AC Motor Control Centers	480 V	Motor Control Centers A A1$^{(1)}$	Motor Control Center B	Motor Control Center C	Motor Control Centers D D1$^{(2)}$
DC buses	125 V	Bus A	Bus B	Bus C	Bus D
AC vital buses	120 V	Bus A	Bus B	Bus C	Bus D

(1) 480 V Load Center A1 and MCC A1 can be supplied from Bus A or B.

(2) 480 V Load Center D1 and MCC D1 can be supplied from Bus C or D.

* Each train of the ac and dc electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

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, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Anticipated Operational Occurrence (AOO) and Postulated Accident (PA) analyses in Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (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, Reactor Coolant System, 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 Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

BASES

LCO (continued)

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). The necessary portions in each mode are controlled by administrative control.

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 subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9, “Distribution Systems - Operating.”

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 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 MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, 3, or 4 would require the unit to be shutdown unnecessarily.

ACTIONS (continued)

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 irradiated 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 subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required Shutdown Margin (SDM) (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive Moderator Temperature Coefficient (MTC) must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does 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 Residual Heat Removal (CS/RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR actions.

BASES

ACTIONS (continued)

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 Surveillance verifies that the ac, dc, and ac vital bus electrical power distribution subsystems are 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 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Chapter 6.

2. Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage pit by the use of the Containment Spray (CS)/Residual Heat Removal (RHR) System pumps. The refueling canal is flooded from the Refueling Water Auxiliary Tank by using the Refueling Water Recirculation Pumps.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

BASES

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pit, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). A detailed discussion of this event is provided in Bases B 3.1.1, "SHUTDOWN MARGIN (SDM)."

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a k_{eff} ≤ 0.95. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

The Applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling canal and the refueling cavity when those volumes are connected to the RCS. When the refueling canal and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g., temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.1.1 This SR ensures that the coolant boron concentration in the RCS, and connected portions of the refueling canal and the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to re-connecting portions of the refueling canal or the refueling cavity to the RCS, this SR must be met per SR 3.0.4. If any dilution activity has occurred while the cavity or canal were disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS. [A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. Subsection 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Isolation Valves

BASES

BACKGROUND	During MODE 6 operations, all isolation valves for reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves must be secured in the closed position. The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by reducing the boron concentration is inappropriate during MODE 6, isolation of all unborated water sources prevents an unplanned boron dilution.
APPLICABLE SAFETY ANALYSES	The possibility of an inadvertent boron dilution event (Ref. 1) occurring during MODE 6 refueling operations is precluded by adherence to this LCO, which requires that potential dilution sources be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portion of the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required for MODE 6. The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that flow paths to the RCS from unborated water sources be isolated to prevent unplanned boron dilution during MODE 6 and thus avoid a reduction in SDM.
APPLICABILITY	In MODE 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of all sources of unborated water to the RCS. For all other MODES, the boron dilution accident was analyzed and was found to be capable of being mitigated.

BASES

ACTIONS

The ACTIONS Table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1

Continuation of CORE ALTERATIONS is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS must be suspended immediately. The Completion Time of "Immediately" for performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

Condition A has been modified by a Note to require that Required Action A.3 be completed whenever Condition A is entered.

A.2

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valves secured closed. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of "Immediately" requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

A.3

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution paths. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that all unborated water sources are isolated, precluding a dilution. The boron concentration is checked every 72 hours during MODE 6 under SR 3.9.1.1. This Surveillance demonstrates that the valves are closed through a system walkdown. [The 31 day Frequency is based on engineering judgment and is considered reasonable in view of other administrative controls that will ensure that the valve opening is an unlikely possibility. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Subsection 15.4.6.

2. NUREG-0800, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The installed source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps) with a 5% instrument accuracy. The detectors also provide continuous visual indication in the control room and an audible alarm and count rate to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly. The audible count rate from the source range neutron flux monitors provides prompt and definite indication of any boron dilution. The count rate increase is proportional to the subcritical multiplication factor and allows operators to promptly recognize the initiation of a boron dilution event. Prompt recognition of the initiation of a boron dilution event is consistent with the assumptions of the safety analysis and is necessary to assure sufficient time is available for isolation of the primary water makeup source before SHUTDOWN MARGINE is lost (Ref.2).

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each monitor must provide visual indication in the control room. In addition, at least one of the two monitors must provide an OPERABLE audible alarm and count rate function to alert the operators to the initiation of a boron dilution event.

BASES

APPLICABILITY	In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation.

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

BASES

ACTIONS (continued)

C.1

With no audible alarm and count rate OPERABLE, prompt and definite indication of a boron dilution event, consistent with the assumptions of the safety analysis, is lost. In this situation, the boron dilution event may not be detected quickly enough to assure sufficient time is available for operators to manually isolate the unborated water source and stop the dilution prior to the loss of SHUTDOWN MARGIN. Therefore, action must be taken to prevent an inadvertent boron dilution event from occurring. This is accomplished by isolating all the unborated water flow paths to the Reactor Coolant System. Isolating these flow paths ensures that an inadvertent dilution of the reactor coolant boron concentration is prevented. The Completion Time of "Immediately" assures a prompt response by operations and requires an operator to initiate actions to isolate an affected flow path immediately. Once actions are initiated, they must be continued until all the necessary flow paths are isolated or the circuit is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

[The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1,“Reactor Trip System (RTS) Instrumentation”. OR the Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The CHANNEL CALIBRATION also includes verification of the audible alarm and count rate function. The [24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. OR the Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.
2. Subsection 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment 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, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment 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 potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment 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 50.34. Additionally, the containment 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 containment. If closed, 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. Alternatively, the equipment hatch can be open provided it can be installed with a minimum of [four] bolts holding it in place.

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 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of irradiated fuel assemblies within containment, the containment air locks must be capable of being closed.

BASES

BACKGROUND (continued)

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted to within regulatory limits.

The Containment Purge System includes two subsystems. The high volume purge system includes a 36 inch purge penetration and a 36 inch exhaust penetration. The second subsystem is a low volume purge system which includes an 8 inch purge penetration and an 8 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the high volume purge and exhaust penetrations are secured in the closed position. The two valves in each of the two low volume purge penetrations can be opened intermittently, but are closed automatically by the Engineered Safety Features Actuation System (ESFAS). Neither of the subsystems is subject to a Specification in MODE 5.

In MODE 6, large air exchangers are necessary to conduct refueling operations. The normal 36 inch high volume purge system is used for this purpose, and all four valves are closed by the ESFAS in accordance with LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

The low volume purge system is not used in MODE 6. All four 8 inch valves are secured in the closed position.

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 and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during irradiated fuel movements (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, 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 (Ref. 2). Fuel handling accidents, analyzed in Reference 3, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.7, "Refueling Cavity Water Level," in conjunction with a minimum decay time of 24 hours prior to irradiated fuel movement without containment closure capability, ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 50.34. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 3), defines "well within" 10 CFR 50.34 to be 25% or less of the 10 CFR 50.34 values. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 50.34 values or the NRC staff approved licensing basis (e.g., a specified fraction of 10 CFR 50.34 limits).

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

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge penetrations. For the OPERABLE containment purge penetrations, this LCO ensures that these penetrations are isolable by the Containment Ventilation Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic purge isolation valve closure times specified in the safety analysis can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

Both containment personnel air lock doors may be open during movement of irradiated fuel or CORE ALTERATION, provided an air lock door is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that: 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the air lock following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of an open air lock can be quickly removed.

BASES

LCO (continued)

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

The equipment hatch may be open during movement of irradiated fuel or CORE ALTERATIONS provided the hatch is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the equipment hatch following an evacuation that would occur in the event of a fuel handling accident, and 3) any

obstructions (e.g., cables and hoses) that would prevent rapid closure ofthe equipment hatch can be quickly removed.

APPLICABILITY

The containment penetration requirements are applicable during movement of irradiated fuel assemblies within containment because this is when there is a potential for the limiting 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 movement of irradiated fuel assemblies within containment is 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

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Ventilation Isolation System not capable of automatic actuation when the purge isolation valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge isolation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge isolation signal.

[The Surveillance is performed every 7 days during movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] A surveillance before the start of refueling operations will provide two or three surveillance verifications during the applicable period for this LCO. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of significant fission product radioactivity to the environment in excess of those recommended by Standard Review Plan Section 15.7.4 (Reference 3).

SR 3.9.4.2

This Surveillance demonstrates that the necessary hardware, tools, and equipment are available to install the equipment hatch. The equipment hatch is provided with a set of hardware, tools, and equipment for moving the hatch from its storage location and installing it in the opening. The required set of hardware, tools, and equipment shall be inspected to ensure that they can perform the required functions.

[The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete the fuel handling operations. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] The Surveillance is modified by a Note which only requires that the Surveillance be met for an open equipment hatch. If the equipment hatch is installed in its opening, the availability of the means to install the hatch is not required.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.4.3

This Surveillance demonstrates that each containment purge isolation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. [The 24 month Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This valve is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations based on sound engineering judgment. In LCO 3.3.2, the Containment Purge Isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT 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. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.] SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These Surveillances 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.

The SR is modified by a Note stating that this Surveillance is not required to be met for valves in isolated penetrations. The LCO provides the option to close penetrations in lieu of requiring automatic actuation capability.

REFERENCES

1. GPU Nuclear Safety Evaluation SE-0002000-001, Rev. 0, May 20, 1988.

2. FSAR Subsection 15.7.4.

3. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the Containment Spray (CS)/RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the CS/RHR heat exchanger(s) and the bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each RHR loop required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

BASES

APPLICABLE SAFETY ANALYSES

While there is no explicit analysis assumptions for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of refueling cavity water level. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE and at least one train of RHR System is operating in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit the CS/RHR pumps to be removed from operation for short durations, under the condition that the boron concentration is not reduced. This conditional stopping of the CS/RHR pumps does not result in a challenge to the fission product barrier.

RHR and Coolant Circulation – High Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Only two RHR loops are required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only two RHR loops are required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least two RHR loops must be OPERABLE and in operation to provide:

a. Removal of decay heat,

b. Mixing of borated coolant to minimize the possibility of criticality, and

c. Indication of reactor coolant temperature.

BASES

LCO (continued)

An OPERABLE RHR loop includes a CS/RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Management of gas voids is important to RHR System OPERABILITY.

The LCO is modified by a Note that allows the required operating RHR loops to be removed from operation for up to 1 hour per 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration by introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1. Boron concentration reduction with coolant at boron concentrations less than required to assure the RCS boron concentration is maintained is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

APPLICABILITY

Two RHR loops must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.7, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

BASES

ACTIONS

RHR loop requirements are met by having two RHR loops OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation or insufficient forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4, A.5, A.6.1, and A.6.2

If no RHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with [four] bolts,

b. One door in each air lock must be closed, and

BASES

ACTIONS (continued)

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that the RHR loops are in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. [The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.5.2

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds an acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

BASES

SURVEILLANCE REQUIREMENTS (continued

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

REFERENCES 1. Subsection 5.4.7.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the Containment Spray (CS)/RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the CS/RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

In MODE 6 Low Water Level, low-pressure letdown line isolation valves are automatically closed upon detection of RCS loop low-level signal to prevent loss of RCS inventory.

The function is effective to prevent core damage during plant shutdown, based on probabilistic risk assessment.

In Mode 6 with low water level (<23 feet above the vessel flange), one additional source of injection water (beyond a CS/RHR pump) will reduce the calculated core damage frequency. One safety injection (SI) pump can provide this injection source. A water source is also required.

The Safeguards Component Area HVAC System is a support system that provides temperature control for the CS/RHR Pump Room and CS/RHR Heat Exchanger Room, and includes electric heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls necessary to perform the support function. The Essential Chilled Water System is a support system and provides chilled water to the air handling unit cooling coil. The Essential Service Water System supports operation of the essential chiller. For each RHR loop required to be OPERABLE, the associated train of Safeguards Component Area HVAC System, including its associated train of the Essential Chilled Water System and Essential Service Water System, must be in operation, or available to operate on demand, and capable of performing its related support function.

BASES

APPLICABLE SAFETY ANALYSES

While there is no explicit analysis assumptions for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of refueling cavity water level. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Three trains of the RHR System are required to be OPERABLE, and two trains in operation, in order to prevent this challenge.

RHR and Coolant Circulation – Low Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The need for one SI pump is based on the PRA insight that maintaining at least one RCS injection function operable results in a reduction in core damage risk during shutdown conditions (Mode 6) with water level <23 feet above the top of the reactor vessel flange.

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, three RHR loops must be OPERABLE. Additionally, two loops of RHR must be in operation in order to provide:

a. Removal of decay heat,

b. Mixing of borated coolant to minimize the possibility of criticality, and

c. Indication of reactor coolant temperature.

The LCO requires the low-pressure letdown line isolation valves to be OPERABLE to mitigate the effects associated with loss of RCS inventory.

The LCO also requires that one SI pump be OPERABLE such that in response to a manual operator start the pump can provide sufficient water to mitigate a drain-down event while in Mode 6 with water level <23 feet above the top of the reactor vessel flange. The LCO requires that a source of water (i.e., reactor water storage pit (RWSP) and water available from the refueling cavity) be available and contain the necessary volume of water. The capability to provide injection water is important to achieve defense-in-depth during Mode 6 with water level <23 feet above the top of the reactor vessel flange. The ability of the pump to provide flow to the RCS while partially filled (and at near atmospheric pressure) and have electrical power are the criteria necessary to be OPERABLE in Mode 6. No pump automatic start features are required to be OPERABLE in Mode 6 as these capabilities were not credited in the PRA.

BASES

LCO (continued)

This LCO is modified by two Notes. Note 1 permits the CS/RHR pumps to be removed from operation for ≤ 15 minutes when switching from one train to another. The circumstances for stopping all CS/RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is maintained > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of 2 hours provided the other loops are OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include that the core time to boil is short, there is no draining operation to further reduce RCS water level and that the capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

An OPERABLE RHR loop consists of a CS/RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Management of gas voids is important to RHR System OPERABILITY.

All CS/RHR pumps may be aligned to the Refueling Water Storage Pit to support filling or draining the refueling cavity or for performance of required testing.

APPLICABILITY

Three RHR loops are required to be OPERABLE, and two RHR loops must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level."

In MODE 6 Low Water Level, low-pressure letdown line isolation valves are automatically closed upon detection of RCS loop low-level signal to prevent loss of RCS inventory.

The function is effective to prevent core damage during plant shutdown, based on probabilistic risk assessment.

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If one low-pressure letdown isolation valve is inoperable, the automatic isolation function to prevent loss of RCS inventory is lost. Action must be initiated to restore the valve to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of three paths for heat removal.

C.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that what would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

C.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore two RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of three OPERABLE RHR loops and at least two operating RHR loop should be accomplished expeditiously..

BASES

ACTIONS (continued)

ACTIONS

C.3, C.4, C.5.1, and C.5.2

If no RHR is in operation, the following actions must be taken:

a. The equipment hatch must be closed and secured with [four] bolts,

b. One door in each air lock must be closed, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions stated above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

The Completion Time of 4 hours allows fixing of most RHR problems and is reasonable, based on the availability of the standby RHR loop and one SI train for injection water, and on the low probability of the coolant boiling in that time.

D.1, D.2, D.3, and D.4

In the event that no SI pump is available to inject water into the RCS, the RWSP does not contain sufficient water volume (SR 3.9.6.5), or boron concentration is not within limits (SR 3.9.6.6) to mitigate a RCS drain-down event in Mode 6 with <23 feet above the top of the reactor vessel flange, then actions must be initiated immediately to restore this capability. The PRA indicates that the availability of an injection water source reduces the core damage frequency. Additionally, until such capability is restored, any activity that could result in lowering RCS water volume must be suspended. The immediate COMPLETION TIME reflects the importance of maintaining water injection capability while the RCS is in a low water level condition.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that two RHR loops are in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loops with the water level in the vicinity of the reactor vessel nozzles, the CS/RHR pump suction requirements must be met. [The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.9.6.2

Verification that the required pump is OPERABLE ensures that an additional RCS or CS/RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.9.6.3

SR 3.9.6.3 requires a complete cycle of each low-pressure letdown isolation valve. This requirements mean confirmation of OPERABILITY of Instrumentation and its control (Setpoints, Channel Checks, Channel Calibrations) and valve. Operating a low-pressure letdown isolation valve through one complete cycle ensures that the low-pressure letdown isolation valve can be automatically actuated to mitigate the effects from loss of RCS inventory. [The Frequency of 24 months is based on engineering judgment, taking into consideration the conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length. This equipment is not at risk of imminent damage as it is designed to remain functional and in good condition while in operation, thus significant degradation due to a longer surveillance interval should not be of major concern. The design reliability is, therefore, maintained by taking these considerations into account based on sound engineering judgment. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.6.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds an acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR System piping and the procedural controls governing system operation.

OR

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.]

SR 3.9.6.5

Verification that the RWSP contains a borated water volume (including water available in the refueling cavity) ≥ 79,920 ft^3 (597,800 gallons) ensures that the pump will have a sufficient inventory of water to mitigate the Mode 6 RCS drain-down event assumed in the probabilistic risk assessment (PRA). [Since the RWSP volume (combined with the available water volume in the refueling cavity) is normally stable, is protected by an alarm, and in view of other administrative controls available, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.9.6.6

The boron concentration of the RWSP should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a RCS drain down event. [Since the RWSP volume (combined with the available water volume in the refueling cavity) is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.6.7

Verification that the breaker alignment is correct and indicated power is available to the required SI pump ensures that the pump motor will be available to drive the pump upon manual start. [The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

SR 3.9.6.8

Periodic surveillance testing of an SI pump to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant PRA for a drain-down event in Mode 6 with <23 ft. SRs are specified in the Inservice Testing Program of the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

REFERENCES 1. Subsection 5.4.7

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pit. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to within values reported in Chapter 15.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.183 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 (Appendix B2 of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Ref. 3). Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as calculated in Reference 2.

BASES

APPLICABILITY

LCO 3.9.7 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not being moved in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pit are covered by LCO 3.7.12, "Fuel Storage Pit Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

[The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely. OR The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.]

REFERENCES

1. Regulatory Guide 1.183, July 2000.

2. Subsection 15.7.4.

3. 10 CFR 50.34

B 3.9 REFUELING OPERATIONS

B 3.9.8 Decay Time

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment or in the fuel handling area requires allowing at least 24 hours for radioactive decay time before fuel assembly handling can be initiated. During fuel handling, this ensures that sufficient radioactive decay has occurred in the event of a fuel handing accident (Refs. 1 and 2). Sufficient radioactive decay of short-lived fission products would have occurred to limit offsite doses from the accident to within the values reported in Chapter 15.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the radioactivity decay time is an initial condition design parameter in the analysis of a fuel handling accident inside containment or in the fuel handling area, as postulated by Regulatory Guide 1.183 (Ref. 1). The fuel handling accident analysis inside containment or in the fuel handling area is described in Reference 2. This analysis assumes a minimum radioactive decay time of 24 hours. Radioactive decay time satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	A minimum radioactive decay time of 24 hours is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment or in the fuel handling area are within the values calculated in Reference 2.
APPLICABILITY	Radioactive decay time is applicable when moving irradiated fuel assemblies in containment or in the fuel handling area. The LCO minimizes the possibility of radioactive release due to a fuel handling accident that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not being moved, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents inside containment or in the fuel handling area are also covered by LCO 3.7.12, “Fuel Storage Pit Water Level” and LCO 3.9.7, “Refueling Cavity Water Level”.
ACTIONS	A.1 With a decay time of less than 24 hours, all operations involving movement of irradiated fuel assemblies within containment or in the fuel

BASES

ACTIONS (continued)

handling area shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

Verification that the reactor has been subcritical for at least 24 hours prior to movement of irradiated fuel in the reactor pressure vessel to the refueling cavity in containment or to the fuel handling area ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Specifying radioactive decay time limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident (Ref. 2).

REFERENCES

1. Regulatory Guide 1.183,"Alternative Radiological Source Terms Evaluating Design Basis Accidents at Nuclear Power Reactors."

2. Subsection 15.7.4

16.2 Combined License Information

COL 16.1(1)	*Adoption of RMTS is to be confirmed and the relevant descriptions are to be fixed.*
COL 16.1(2)	*Adoption of SFCP is to be confirmed and the relevant descriptions are to be fixed.*
COL 16.1_3.3.1(1)	*Deleted.*
COL 16.1_3.3.2(1)	*Deleted.*
COL 16.1_3.3.2(2)	*LCO 3.3.2 and associated Bases for hazardous chemical are to be confirmed by the evaluation with site-specific condition.*
COL 16.1_3.3.4(1)	*Component controls and instrumentation required for safe shutdown related to the Ultimate Heat Sink in Tables B 3.3.4-1 and B 3.3.4-2 to be specified.*
COL 16.1_3.3.5(1)	*Deleted.*
COL 16.1_3.3.6(1)	*Deleted.*
COL 16.1_3.4.17(1)	*Deleted.*
COL 16.1_3.7.9(1)	*LCO 3.7.9 and associated Bases for the Ultimate Heat Sink based on plant specific design, including required UHS water volume, lowest water level for ESW pumps and maximum water temperature of the UHS, are to be developed.*
COL 16.1_3.7.10(1)	*LCO 3.7.10 and associated Bases for hazardous chemical are to be confirmed by the evaluation with site-specific condition.*
COL 16.1_3.8.4(1)	*The battery float current values in required action A.2 is to be confirmed after selection of the plant batteries.*
COL 16.1_3.8.5(1)	*The battery float current values in required action A.2 is to be confirmed after selection of the plant batteries.*
COL 16.1_3.8.6(1)	*The battery float current values in condition B, required action B.2, and SR 3.8.6.1 are to be confirmed after selection of the plant batteries.*
COL 16.1_4.1(1)	*The site specific information for site location is to be provided.*
COL 16.1_4.3.1(1)	*Deleted.*
COL 16.1_5.1.1(1)	*The titles for members of the unit staff are to be specified .*
COL 16.1_5.1.2(1)	*The titles for members of the unit staff are to be specified .*

COL 16.1_5.2.1(1)	*The titles for members of the unit staff are to be specified.*
COL 16.1_5.2.2(1)	*The titles and number for members of the unit staff are to be specified.*
COL 16.1_5.3.1(1)	*Minimum qualification for unit staff is to be specified.*
COL 16.1_5.5.1(1)	*The titles for members of the unit staff that approve the Offsite Dose Calculation Manual are to be specified.*
COL 16.1_5.5.9(1)	*Deleted.*
COL 16.1_5.5.20(1)	*Control Room Envelope Habitability Program for hazardous chemical are to be confirmed by the evaluation with site-specific condition.*
COL 16.1_5.6.1(1)	*In case of multiple unit site, the additional information for submittal of report is to be added.*
COL 16.1_5.6.1(2)	*The format of the Annual Radiological Environmental Operating Report is to be specified based on "the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979" or another format.*
COL 16.1_5.6.2(1)	*In case of multiple unit site, the additional information for submittal of report is to be added.*
COL 16.1_5.6.7(1)	*Deleted.*
COL 16.1_5.7(1)	*The site specific information about High Radiation Area is to be provided.*