Entergy Operations, Inc.
P. O. Box 756
Port Gibson, MS 39150

Kevin Mulligan
Site Vice President
Grand Gulf Nuclear Station
Tel. (601) 437-7500

Attachment 5 contains **PROPRIETARY** information

GNRO-2016/00024

May 17, 2016

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Operating License Manual Update Submittal
Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
License No. NPF-29

REFERENCE:

1 Entergy Letter GNRO-2014/00057, Technical Requirements Manual and Technical Specification Bases Update (ML14241A308)

2 Entergy Letter GNRO-2014/00058, Technical Requirements Manual and Technical Specification Bases Update (ML14241A309)

3 Entergy Letter GNRO-2015/00043, Pressure and Temperature Limits Report (PTLR) Up to 54 Effective Full-Power Years (EFPY) in support of the License Amendment Request Application to Revise Grand Gulf Nuclear Station Unit 1's Current Fluence Methodology from 0 EFPY Through the End of Extended Operations to a Single Fluence Method

Dear Sir or Madam:

Pursuant to 10 CFR 50.71(e), Entergy Operations Inc. herby submits an update of all changes made to the Grand Gulf Nuclear Station Operating License Manual (Technical Specification Bases, Technical Requirement Manual, and Offsite Dose Calculation Manual, since the last submittals (References 1 and 2 above). The Pressure Temperature Limits Report) was last submitted under Reference 3 as a proprietary document and is being resubmitted in accordance with the requirements of 10 CFR 50.71(e).

This letter contains no new commitments. If you have any questions or require additional information, please contact James Nadeau at 601-437-2103.

When Attachment 5 is removed from this letter, the entire document is
NON-PROPRIETARY

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 17th day of May 2016.

Sincerely,

KJM/ram

Attachment(s):
1. Change Summary
2. Technical Specification Bases Changes
3. Technical Requirements Manual Changes
4. Offsite Dose Calculation Manual Changes
5. Pressure Temperature Limit Report Changes
6. GEH Affidavit

cc: without Attachment(s)

U.S. Nuclear Regulatory Commission
ATTN: Mr. Jim Kim, NRR/DORL (w/2)
Mail Stop OWFN 8 B1
Rockville, MD 20852-2738

NRC Senior Resident Inspector
Grand Gulf Nuclear Station
Port Gibson, MS 39150

U. S. Nuclear Regulatory Commission
ATTN: Marc L. Dapas (w/2)
Regional Administrator, Region IV
1600 East Lamar Boulevard
Arlington, TX 76011-4511

Attachment 1

GNRO-2016/00024

Change Summary

LBDCR Number	Topic of Change	Affected Technical Specification Bases Pages
2011-0002	Placement of Radial Well into Service	ODCM Figure 3.0-1
2011-0026	EPU Main Steam Line High Flow Isolation Setpoint Change	TRM Page 3.3-58 – II
2013-0009	Fire Protection TRM requirements updated for 24 month fuel cycle	TRM Pages 6.2-2, 6.2-23, 6.2-25, 6.2-27, and 6.2-34
2013-0024	Addition of ODCM 6.3.9 Condition E and applicable C and Change Condition D to be only applicable to Condition B	ODCM Page A-14
2014-0026	Technical Specification Bases and UFSAR update to remove Division I and II high vibration trips and alarms	TS Bases Pages B3.8-25,
2014-0027	First Stage Turbine Pressure Instrument Sensing Line Failure Multiple Times Requiring Temporary Modification	TRM Pages 3.3-8 – II, 3.3-18 – II, and 3.3-28 – I TS Bases Pages B3.3-15, B3.3-17, B3.3-28, B3.3-40, B3.3-41, B3.3-46, B3.3-68, B3.3-69a, B3.3-70, and B3.3-71
2014-0029	Provide for Beyond Design Basis External Event Containment Vent Capability	TRM Pages 3.6-17-VIII and 3.6-17-XVI
2014-0034	Technical Specification Bases updates for 24 month fuel cycle	TS Bases Pages B3.3-27a, B3.3-29a, B3.3-47, B3.3-86, B3.4-31, B3.7-30, and B3.8-26
2014-0040	Revise TRM temperature limits for the Reactor Water Cleanup Heat Exchanger Room valve nest area	TRM Page 6.7-7
2014-0043	Technical Specification Bases update associated with Amendment 201	TS Bases Pages B3.3-236, B3.3-327, B3.3-328, B3.5-7, B3.5-8, B3.5-8a, B3.5-12, B3.5-13a, B3.5-14, B3.6-32, B3.6-33, B3.6-34, B3.6-35, B3.6-38, B3.6-42, B3.6-43, B3.6-46, B3.6-47, B3.6-58, B3.6-85, B3.6-87a, B3.6-98, B3.6-98a, B3.6-99, B3.6-101, B3.6-128, B3.6-129, B3.6-130, B3.6-131, B3.7-5, B3.7-6, B3.7-7, B3.7-15, B3.7-16, B3.7-16a, B3.7-16c, B3.7-16d, B3.7-18, B3.7-19, B3.7-21, B3.7-23, B3.7-24, B3.8-13, B3.8-14, B3.8-15, B3.8-15a, B3.8-55, B3.8-56, B3.8-56a, B3.5-57, B3.5-58, B3.8-59, B3.8-77, B3.8-77a, and B3.8-78

LBDCR Number	Topic of Change	Affected Technical Specification Bases Pages
2014-0044	Technical Specification Bases update associated with Amendment 202	TS Bases Pages B3.4-43, B3.4-46, B3.4-46a, B3.4-48, B3.4-51, B3.4-51a, B3.5-5, B3.5-8b, B3.5-9, B3.5-10, B3.5-15, B3.5-19, B3.5-22, B3.5-24, B3.5-24a, B3.6-39, B3.6-40, B3.6-57, B3.6-59, B3.8-34, B3.9-26, B3.9-28b, B3.9-28c, B3.9-30, B3.9-33, and B3.9-34
2014-0049	Technical Specification Bases update associated with Amendment 208	TS Bases Pages B3.6-100 and B3.7-16b
2014-0050	Editorial Change to correct typographical error in Technical Specification Bases	TS Bases Page B3.8-47
2015-0001	Revise TRM and UFSAR for 24 month fuel cycle changes missed during LBDCR 2013-0013	TRM Page 7-6
2015-0005	Revise TRM for Seismic Monitoring System Instrumentation	TRM Pages 6.3-7 and 6.3-8
2015-0006	Editorial changes to correct typographical errors	TRM Page 6.3-7
2015-0015	Clarification of Technical Specification Bases for Surveillance Requirement 3.8.3.4	TS Bases Page B3.8-48
2015-0016	Editorial changes to correct typographical errors	TS Bases Page B3.4-20
2015-0017	Technical Specification Bases update associated with Amendment 209	TS Bases Page B3.6-105
2015-0026	TRM update to allow one-time extension of surveillance requirement for valve testing	TRM Page 6.3-18
2015-0027	TRM update to capture operating experience from River Bend Station	TRM Pages 6.7-2 and TRB-3
2015-0029	TRM update to allow one-time extension of surveillance requirement for Division III Emergency Diesel Fuel Tank	TRM Page 3.8-24-I
2015-0046	Technical Specification Bases and UFSAR updates for recalculated maximum load reject for the Division I, II, & III Emergency Diesel Generators	TS Bases Page B3.8-19
2015-0050	TRM Bases update for TRM Requirements 6.4.1, 6.7.1, 6.8.1, and 6.8.2	TRM Pages TRB-3, TRB-4, and TRB-5
2015-0056	Adoption of License Amendment 204 for Fluence in the UFSAR and PTLR	PTLR – All pages 1-171

LBDCR Number	Topic of Change	Affected Technical Specification Bases Pages
2015-0058	Technical Specification Bases update for Surveillance Requirements 3.6.4.1.3 and 3.6.4.1.4	TS Bases Page 3.6-87
2015-0066	TRM, Technical Specification Bases, and UFSAR updates to address MELLLA+	TRM Pages 3.6-17-XVII and 3.6-53-I TS Bases Pages B3.6-2 and B3.6-6
2015-0076	TRM update to allow one-time extension of surveillance requirement for Division III Emergency Diesel Fuel Tank	TRM Page 3.8-24-I
2016-0003	Editorial changes to correct typographical error in Technical Specification Bases	TS Bases Pages B3.6-37 and B3.6-76
2016-0007	Revision Technical Specification Bases 3.8.1, Condition B.4 to address NRC identified concern	TS Bases Pages B3.8-8, B3.8-8a, and B3.8-8b
2016-0015	Addition of TRM Section 6.10, Beyond Design Basis Components	TRM Pages 6.10-1, 6.10-2, 6.10-3, 6.10-4, 6.10-5, 6.10-6, 6.10-7, TRB-6, and TRB-7 Table of Contents Pages vii and viia
2016-0033	TRM and Technical Specification Bases update to eliminate confusing wording associated with Containment Spray System testing	TS Bases Pages B3.6-40a and B3.6-40b
2016-0042	Update TRM to take credit for the Main Turbine Electrical Overspeed Trip Device	TRM Pages 6.3-17 and TRB-2

Attachment 2

GNRO-2016/00024

Technical Specification Bases Changes

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8.a, b. Scram Discharge Volume Water Level - High (continued)

in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

9. Turbine Stop Valve Closure, Trip Oil Pressure - Low

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve Closure, Trip Oil Pressure - Low Function is the primary scram signal for the turbine trip event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

Turbine Stop Valve Closure, Trip Oil Pressure - Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each stop valve. Two independent pressure transmitters are associated with each stop valve. One of the two transmitters provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve Closure, Trip Oil Pressure - Low channels, each consisting of one pressure transmitter. The logic for the Turbine Stop Valve Closure, Trip Oil Pressure - Low Function is such that three or more TSVs must be closed to produce a scram.

This Function must be enabled at THERMAL POWER ≥ 35.4% RTP, which is the Analytical Limit. This is normally accomplished automatically by reactor power signals derived from the power range neutron monitoring system.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low (continued)

with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 35.4% RTP. This is normally accomplished automatically by reactor power signals derived from the power range neutron monitoring system. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Stop Valve Closure, Trip Oil Pressure - Low Function.

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

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ 35.4% RTP. This Function is not required when THERMAL POWER is < 35.4% RTP since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Functions are adequate to maintain the necessary safety margins.

11. Reactor Mode Switch-Shutdown Position

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

The reactor mode switch is a single switch with four channels, each of which inputs into one of the RPS logic channels.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.10, SR 3.3.1.1.12 and SR 3.3.1.1.17 (continued)

Note 3 to SR 3.3.1.1.10 states that the APRM recirculation flow transmitters are excluded from CHANNEL CALIBRATION of Function 2.d, Average Power Range Monitor Flow Biased Simulated Thermal Power - High. Calibration of the flow transmitters is performed on an 24-month frequency (SR 3.3.1.1.17).

SR 3.3.1.1.10 for the designated function is modified by two notes identified in Table 3.3.1.1-1. The first note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluating channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in channel performance prior to returning the channel to service. Performance of these channels will be evaluated under the Corrective Action Program. Entry into the Corrective Action Program ensures required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY.

The second note requires that the as-left setting for the channel be within the as-left tolerance of the Nominal Trip Setpoint (NTSP). Where a setpoint more conservative than the NTSP issued in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NSP, then the channel shall be declared inoperable. The second note also requires the NTSP and the methodologies for calculating the as-left and the as-found tolerances to be in the Technical Requirements Manual

The Frequency of 24 months for SR 3.3.1.1.12 and SR 3.3.1.1.17 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

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

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

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve Closure, Trip Oil Pressure - Low and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 35.4% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoint.

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 35.4% RTP, then the affected Turbine Stop Valve, Trip Oil Pressure - Low and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.15 (continued)

RPS RESPONSE TIME tests are conducted on an 24_month STAGGERED TEST BASIS. Note 3 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal.

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

SR 3.3.1.1.16 and SR 3.3.1.1.18

Deleted

(continued)

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

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

The purpose of the RWL is to limit control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RWL supplies a trip signal to the Rod Control and Information System (RCIS) to appropriately inhibit control rod withdrawal during power operation equal to or greater than the low power setpoint (LPSP). The RWL has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. The rod block logic circuitry in the RCIS is arranged as two redundant and separate logic circuits. These circuits are energized when control rod movement is allowed. The output of each logic circuit is coupled to a comparator by the use of isolation devices in the rod drive control cabinet. The two logic circuit signals are compared and rod blocks are applied when either circuit trip signal is present. Control rod withdrawal is permitted only when the two signals agree. Each rod block logic circuit receives control rod position indication from a separate channel of the Rod Position Information System, each with a set of reed switches for control rod position indication. Control rod position is the primary data input for the RWL. The power range neutron monitoring system is used to determine reactor power level, with an LPSP and a high power setpoint (HPSP) used to determine allowable control rod withdrawal distances. Below the LPSP, the RWL is automatically bypassed (Ref. 1).

(continued)

BASES

BACKGROUND (continued)

The purpose of the RPC is to ensure control rod patterns during startup are such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. The RPC, in conjunction with the RCIS, will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the specified sequence. The rod block logic circuitry is the same as that described above. The RPC also uses the power range neutron monitoring system to determine when reactor power is above the power at which the RPC is automatically bypassed (Ref. 1).

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

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Rod Withdrawal Limiter

The RWL is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 2. A statistical analysis of RWE events was performed to determine the MCPR response as a function of withdrawal distance and initial operating conditions. From these responses, the fuel thermal performance was determined as a function of RWL allowable control rod withdrawal distance and power level.

The RWL satisfies Criterion 3 of the NRC Policy Statement. Two channels of the RWL are available and are required to be OPERABLE to ensure that no single instrument failure can preclude a rod block from this Function. The RWL high power function channels are OPERABLE when control rod withdrawal is limited to no more than two notches. The RWL low power function channels are OPERABLE when control rod withdrawal is limited to no more than four notches.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1, SR 3.3.2.1.2, SR 3.3.2.1.3, and SR 3.3.2.1.4 (continued)

control rod block occurs. Proper operation of the RWL is verified by SR 3.3.2.1.1 which verifies proper operation of the two-notch withdrawal limit and SR 3.3.2.1.2 which verifies proper operation of the four-notch withdrawal limit. Proper operation of the RPC is verified by SR 3.3.2.1.3 and SR 3.3.2.1.4. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. As noted, the SRs are not required to be performed until 1 hour after specified conditions are met (e.g., after any control rod is withdrawn in MODE 2). This allows entry into the appropriate conditions needed to perform the required SRs. The Frequencies are based on reliability analysis (Ref. 7).

SR 3.3.2.1.5

The LPSP is the point at which the RPCS makes the transition between the function of the RPC and the RWL. This transition point is automatically varied as a function of power. This power level is derived from the power range neutron monitoring system (one channel to each trip system). These power setpoints must be verified periodically to be within the Allowable Values. If any LPSP is nonconservative, then the affected Functions are considered inoperable. Since this channel has both upper and lower required limits, it is not allowed to be placed in a condition to enable either the RPC or RWL Function. Because main turbine bypass steam flow can affect the LPSP nonconservatively for the RWL, the RWL is considered inoperable with any main turbine bypass valves open. The Frequency of 92 days is based on the setpoint methodology utilized for these channels.

SR 3.3.2.1.6

This SR ensures the high power function of the RWL is not bypassed when power is above the HPSP. The analytical limit for the HPSP is 70%. The power level is derived from the power range neutron monitoring system. Periodic testing of the HPSP channels is required to verify the setpoint to be less than or equal to the limit. Adequate margins in accordance with setpoint methodologies are included. If the HPSP is nonconservative, then the RWL is considered inoperable. Alternatively, the HPSP can be placed in the conservative condition (nonbypass). If placed

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.6 (continued)

in the nonbypassed condition, the SR is met and the RWL would not be considered inoperable. Because main turbine bypass steam flow can affect the HPSP nonconservatively for the RWL, the RWL is considered inoperable with any main turbine bypass valve open. The Frequency of 92 days is based on the setpoint methodology utilized for these channels.

SR 3.3.2.1.7

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

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.2.1.8

The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch—Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable limits. This allows entry into MODES 3 and 4 if the 24 month Frequency is not met per SR 3.0.2.

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

(continued)

BASES

BACKGROUND (continued)	system trips one of the two EOC-RPT breakers for each recirculation pump and the second trip system trips the other EOC-RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV Closure, Trip Oil Pressure - Low and the TCV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps from fast speed operation in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and pressure transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in References 2, 3, and 4.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps from fast speed operation after initiation of initial closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT as specified in the COLR are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled the power range neutron monitoring system indicates < 35.4% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement.

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

transmitter associated with each stop valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TSV Closure, Trip Oil Pressure - Low Function is such that two or more TSVs must be closed to produce an EOC-PT. This Function must be enabled at THERMAL POWER ≥ 35.4% RTP. This is normally accomplished automatically by reactor power signals derived from the power range neutron monitoring system.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Turbine Stop Valve Closure, Trip Oil Pressure - Low (continued)

Reactor power signals derived from the power range neutron monitoring system. Four channels of TSV Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV Closure, Trip Oil Pressure - Low Allowable Value is selected high enough to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 35.4% RTP with any recirculating pump in fast speed. Below 35.4% RTP or with the recirculation in slow speed, the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor (APRM) Fixed Neutron Flux - High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

TCV Fast Closure, Trip Oil Pressure - Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure - Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Fast closure of the TCVs is determined by measuring the EHC fluid pressure at each control valve. There is one pressure transmitter associated with each control valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure - Low Function is such that two or more TCVs must be closed (pressure transmitter trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 35.4% RTP. This is normally accomplished automatically by reactor power signals derived from the power range neutron monitoring system. Four channels of TCV Fast Closure, Trip Oil Pressure — Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure - Low Allowable Value is selected high enough to detect imminent TCV fast closure.

This protection is required consistent with the analysis, whenever the THERMAL POWER is ≥ 35.4% RTP with any recirculating pump in fast speed. Below 35.4% RTP or with recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure - High and the APRM Fixed Neutron Flux - High Functions of the RPS are adequate to maintain the necessary safety margins.

ACTIONS

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.4

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

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.2.5

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

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

REFERENCES

1. UFSAR, Section 5.4.1.7.10.

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

BASES

ACTIONS

B.1 (continued)

OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

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

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, the plant must be brought to a MODE in which overall plant risk is minimized. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

ACTIONS

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies (Required Action D.1). This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. All actions must continue until the applicable Required Actions are completed.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

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

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.2.2

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2.3

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

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

REFERENCES

1. FSAR, Section 8.3.1.1.5.
2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
3. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1 (continued)

lift settings must be performed during shutdown, since this is a bench test, and in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The safety lift setpoints will still be set within a tolerance of ± 1 percent, but the setpoints will be tested to within ± 3 percent to determine acceptance or failure of the as-found valve lift setpoint. If a valve is tested and the lift setpoint is found outside the 3 percent tolerance, two additional valves are to be tested (Reference 4).

The Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.

SR 3.4.4.2

The required relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

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

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.4.4.3

A manual actuation of each required S/RV (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1 (continued)

The Frequency is every 2 years and is required by the Inservice Testing Program per the ASME Code requirement (Ref. 6).

Therefore, this SR is modified by a Note that states the leakage Surveillance is only required to be performed in MODES 1 and 2. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. NUREG-0677, "The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes," May 1980.
6. ASME code for Operation and Maintenance of Nuclear Power Plants, 2001 Edition thru 2003 Addendums with portions of 2004 Edition, Subsection IST C-3630.
7. NEDC-31339, "BWR Owners Group Assessment of ECCS Pressurization in BWRs," November 1986.

BASES

LCO (continued)

OPERABLE RHR pump, two heat exchangers in series, and the associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System Operability.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS — Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

In MODE 3 with reactor steam dome pressure below the RHR cut in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR System may be operated in the

(continued)

BASES

ACTIONS

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

separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling system or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

SR 3.4.9.2

RHR Shutdown Cooling 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 RHR shutdown cooling system subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling 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

(continued)

BASES

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 Shutdown Cooling 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 that the RHR Shutdown Cooling 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 Shutdown Cooling 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 subset 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.

This SR is modified by a Note that states the SR is not required to be performed until 12 hours after reactor steam dome pressure is < [the RHR cut in permissive pressure]. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering the Applicability.

The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR Shutdown Cooling System piping and the procedural controls governing system operation.

REFERENCES None.

BASES

LCO (continued)

aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

Note 3 permits both RHR shutdown cooling subsystems and recirculation pumps to not be in operation during performance of inservice leak testing and during hydrostatic testing. This is permitted because RCS pressures and temperatures are being closely monitored as required by LCO 3.4.11.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS — Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1 (continued)

determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

SR 3.4.10.2

RHR Shutdown Cooling 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 RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling 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 Shutdown Cooling 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 that the RHR Shutdown Cooling 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 Shutdown Cooling 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 subset 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

(Continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.10.2 (continued)

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.

The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR Shutdown Cooling System piping and the procedural controls governing system operation.

REFERENCES

None.

BASES (continued)

LCO

Each ECCS injection/spray subsystem and eight ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are the three LPCI subsystems, the LPCS System, and the HPCS System. The ECCS injection/spray subsystems are further subdivided into the following groups:

a) The low pressure ECCS injection/spray subsystems are the LPCS System and the three LPCI subsystems;

b) The ECCS injection subsystems are the three LPCI subsystems; and

c) The ECCS spray subsystems are the HPCS System and the LPCS System.

Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).
LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of an RHR shutdown cooling loop when necessary or alignment to allow for the Alternate Decay Heat Removal System (ADHRS) once MODE 4 is reached.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, the ADS function is not required when pressure is # 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS — Shutdown."

(continued)

ACTIONS (continued)

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 12.

D.1

If any Required Action and associated Completion Time of Condition A, B, or C are not met, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 13) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action D.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

ACTIONS (continued)

E.1

The LCO requires eight ADS valves to be OPERABLE to provide the ADS function. Reference 14 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only seven ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a portion of a high pressure (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

G.1

If any Required Action and associated Completion Time of Condition E or F are not met or if two or more ADS valves are inoperable, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 13) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS (continued)

G.1

Required Action G.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a degraded condition not specifically justified for continued operation, and may be in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained air. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem 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 injection/spray subsystem 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 that the ECCS injection/spray subsystems are 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 injection/spray subsystem 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 subset 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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1 (continued)

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.

The 31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary or alignment to allow for the operation of the ADHRS when MODE 4 is reached.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

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 if directed.

SR 3.5.1.3

Verification every 31 days that ADS accumulator supply pressure is ≥ 150 psig assures adequate air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 15). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of 150 psig is provided by the ADS Instrument Air Supply System. The 31 day Frequency takes into consideration administrative control over operation of the Instrument Air Supply System and alarms for low air pressure.

SR 3.5.1.4

The performance requirements of the ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME requirements (Ref. 19) for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system head that is equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.6

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.7 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

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

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each required ADS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by method 1), plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 20), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

alternately tested. The Frequency of the required relief-mode actuator testing was developed based on the tests required by ASME OM, Part 1, (Ref. 20) as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.8

This SR ensures that the HPCS System response time is less than or equal to the maximum value assumed in the accident analysis. Specific testing of the ECCS actuation instrumentation inputs into the HPCS System ECCS SYSTEM RESPONSE TIME is not required by this SR. Specific response time testing of this instrumentation is not required since these actuation channels are only assumed to respond within the diesel generator start time; therefore, sufficient margin exists in the diesel generator 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test (Ref. 17). The diesel generator starting and any sequence loading delays along with the Reactor Vessel Water Level - Low Low, Level 2 confirmation delay permissive must be added to the HPCS System equipment response times to obtain the HPCS System ECCS SYSTEM RESPONSE TIME. The acceptance criterion for the HPCS System ECCS SYSTEM RESPONSE TIME is # 32 seconds.

HPCS System ECCS SYSTEM RESPONSE TIME tests are conducted every 24 months. This Frequency is consistent with the typical industry refueling cycle and is based on industry operating experience.

(continued)

REFERENCES

1. FSAR, Section 6.3.2.2.3.
2. FSAR, Section 6.3.2.2.4.
3. FSAR, Section 6.3.2.2.1.
4. FSAR, Section 6.3.2.2.2.
5. FSAR, Section 15.2.8.
6. FSAR, Section 15.6.4.
7. FSAR, Section 15.6.5.
8. 10 CFR 50, Appendix K.
9. FSAR, Section 6.3.3.
10. 10 CFR 50.46.
11. FSAR, Section 6.3.3.3.
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
13. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
14. FSAR, Section 6.3.3.7.8
15. FSAR, Section 7.3.1.1.1.4.2.
16. GNRI-96/00229, Amendment 130 to the Operating License.
17. NEDO-32291-A, "System Analyses for Elimination of Selected Response Time Testing Requirements," October 1995.
18. GNRI-97/00181, Amendment 133 to the Operating License.
19. ASME/ANSI OM-1987, Operation and Maintenance of Nuclear Pumps in Light Water Reactor Power Plants.
20. ASME Code of Operation and Maintenance of Nuclear Power Plants, Part 1.

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 ECCS — Shutdown

BASES

BACKGROUND	A description of the High Pressure Core Spray (HPCS) System, Low Pressure Core Spray (LPCS) System, and low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS — Operating."
APPLICABLE SAFETY ANALYSES	ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one ECCS injection/spray subsystem is required, post LOCA, to maintain the peak cladding temperature below the allowable limit. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one ECCS subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two ECCS subsystems are required to be OPERABLE in MODES 4 and 5. The ECCS satisfy Criterion 3 of the NRC Policy Statement.
LCO	Two ECCS injection/spray subsystems are required to be OPERABLE. At least one of the required ECCS subsystems must have a OPERABLE diesel generator capable of supplying electrical power. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the reactor pressure vessel (RPV). The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY. One LPCI subsystem may be aligned for decay heat removal in MODE 4 or 5 and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 (continued)

initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

In MODES 4 and 5, the RHR System may operate in the shutdown cooling mode, or be aligned to allow alternate means to remove decay heat and sensible heat from the reactor. Therefore, RHR valves that are required for LPCI subsystem operation may be aligned for decay heat removal. One LPCI subsystem of the RHR System may be considered OPERABLE for the ECCS function if all the required valves in the LPCI flow path can be manually realigned (remote or local) to allow injection into the RPV and the system is not otherwise inoperable. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.

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 if directed.

(continued)

BASES

BACKGROUND (continued)

The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge line "keep fill" system is designed to maintain the pump discharge line filled with water.

APPLICABLE SAFETY ANALYSES

The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system is included in the Technical Specifications as required by the NRC Policy Statement.

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event. Management of gas voids is important to RCIC System OPERABILITY.

APPLICABILITY

The RCIC System is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC system and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The RCIC System flow path 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 RCIC System and may prevent a water hammer, pump cavitation, and pumping of noncondensible gas.

Selection of RCIC System locations susceptible to gas accumulation is based on a self-assessment of the piping configuration to identify where gases may accumulate and remain even after the system is filled and vented, and to identify vulnerable potential degassing flow paths. The review is supplemented by verification that installed high-point vents are actually at the system high points, including field verification to ensure pipe shapes and construction tolerances have not inadvertently created additional high points. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC 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 that the RCIC Systems are 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.

RCIC 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.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

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 if directed.

(continued)

BASES

BACKGROUND (continued)	This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.
APPLICABLE SAFETY ANALYSES	The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage. Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded. The maximum allowable leakage rate for the primary containment (L_a) is 0.682% by weight of the containment and drywell air per 24 hours at the maximum peak containment pressure (P_a) of 12.1 psig (Ref. 4). Primary containment satisfies Criterion 3 of the NRC Policy Statement.
LCO	Primary containment OPERABILITY is maintained by limiting leakage to $\leq$ 1.0 L_a, except prior to the first unit startup after performing a required 10 CFR 50, Appendix J leakage test. At this time, the combined Type B and Type C leakage must be < 0.6 L_a, and the overall Type A leakage must be < 0.75 L_a. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those

(continued)

BASES

BACKGROUND (continued)	DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.682% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of 12.1 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. Primary containment air locks satisfy Criterion 3 of the NRC Policy Statement.
LCO	As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, both air lock doors must be OPERABLE, and the test connection valves must be OPERABLE in accordance with LCO 3.6.1.3. These normally closed manual isolation valves are considered OPERABLE when closed or when intermittently opened under administrative controls. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low-Low Set (LLS) Valves

BASES

BACKGROUND

The safety/relief valves (S/RVs) can actuate either in the relief mode, the safety mode, the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (one of the power actuated modes of operation), a pneumatic operator and mechanical linkage overcome the spring force and open the valve. The main valve can be maintained open with valve inlet steam pressure as low as 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.

Six of the S/RVs are equipped to provide the LLS function. The LLS logic causes two LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and causes all the LLS valves to stay open longer, such that reopening of more than one S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short duration S/RV cycles with valve actuation at the relief setpoint.

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

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of one S/RV operating on "subsequent actuations" is met (Ref. 1). In other words, multiple simultaneous openings of S/Rvs (following the initial opening) and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis Accidents (DBAs). Furthermore, the LLS function justifies the primary containment analysis assumption that multiple simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though six LLS S/RVs are specified, all six LLS S/RVs do not operate in any DBA analysis.

LLS valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

Six LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 2). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.

(continued)

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of S/RVs. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the LLS valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

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

B.1

If the inoperable LLS valve cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3) and because the time spent to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

ACTIONS

C.1 and C.2

If two or more LLS valves are inoperable, there could be excessive short duration S/RV cycling during an overpressure event. The plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each required LLS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by method 1), plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 4), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by method 2), valve OPERABILITY has been demonstrated for all installed LLS valves based upon the successful operation of a test sample of S/RVs.

1. Manual actuation of the LLS valve, with verification of the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or pressure). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer.

2. The sample population of S/RVs tested each refueling outage to satisfy SR 3.4.4.1 will be stroked in the relief mode during "as-found" testing to verify proper operation of the S/RV. Just prior to installation of the to be newly-installed S/RVs to satisfy SR 3.4.4.1 the valve will be stroked in the relief mode during certification testing to verify proper operation of the S/RV.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1 (continued)

The successful performance of the test sample of S/RVs provides reasonable assurance that the remaining installed S/RVs will be perform in a similar fashion. After the S/RVs are replaced, the electrical and pneumatic connections shall be verified either through mechanical/electrical inspection or test prior to the resumption of electric power generation to ensure that no damage has occurred to the S/RV during transportation and installation. This verifies that each replaced S/RV will properly perform its intended function.

The STAGGERED TEST BASIS Frequency ensures that both solenoids for each LLS valve relief-mode actuator are alternatively tested. The Frequency of the required relief-mode actuator testing is based on the tests required by ASME OM Part 1 (Ref. 3), as implemented by the Inservice Testing Program of Specification 5.5.6. The testing Frequency required by the Inservice Testing Program is based on operating experience and valve performance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. (Reference 4)

SR 3.6.1.6.2

The LLS designed S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

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

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

REFERENCES

1. GESSAR-II, Appendix 3B, Attachment A, Section 3BA.8.
2. FSAR, Section 5.2.2.2.3.3.
3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants, Part 1.
5. GNRI-96/00229, Amendment 130 to the Operating License.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment spray operation is also assumed in the design basis LOCA dose analysis to scrub iodine from the containment atmosphere thereby mitigating the affects of the accident.

The RHR Containment Spray System satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a Design Basis Accident (DBA), a minimum of one RHR containment spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below design limits. To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Containment Spray System OPERABILITY.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR containment spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one RHR containment spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE RHR containment spray subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time was chosen in light of the redundant RHR containment capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR containment spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1

If the inoperable RHR containment spray subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

Two Notes have been added to this SR. The first Note allows RHR containment spray subsystems to be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. At these low pressures and decay heat levels (the reactor is shut down in MODE 3), a reduced complement of subsystems should provide the required containment pressure mitigation function thereby allowing operation of an RHR shutdown cooling loop when necessary. The second Note 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 path if directed.

SR 3.6.1.7.2

RHR Containment Spray 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 RHR suppression pool spray subsystems and may also prevent water hammer and pump cavitation. Selection of RHR Containment Spray 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 Containment Spray 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.2 (continued)

evaluation that the RHR Containment Spray 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 Containment Spray 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 subset 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.

The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR Containment Spray System piping and the procedural controls governing system operation.

SR 3.6.1.7.3

Verifying each RHR pump develops a flow rate ≥ 7450 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded below the required flow rate during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 2). 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.4

This SR verifies that each RHR containment spray subsystem automatic valve actuates to its correct position upon receipt of an actual or simulated automatic actuation signal. Actual spray initiation is not required to meet this SR. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.6 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.7.5 and TRM SR 3.6.1.7.1

The following surveillances are performed to demonstrate the Containment Spray System remains unobstructed and capable of flowing water when required. The testing practices and frequencies (as discussed below) are adequate to demonstrate the system will perform as required.

SR 3.6.1.7.5

This surveillance is performed to verify the spray nozzles are not obstructed. This surveillance may be accomplished by verifying the nozzle openings are free of material that would obstruct the flow of water or the performance of an air flow test through each nozzle. The type of testing utilized should be based on system operating history and the availability of the appropriate testing equipment. UFSAR Section 6.2.2.2 (Reference 3) defines preoperational testing performed on the system, which is not required to be duplicated by the performance of this surveillance testing. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through industry operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.5 and TRM SR 3.6.1.7.1 (continued)

TRM SR 3.6.1.7.1

This surveillance will be performed following a maintenance activity that had the potential to introduce foreign material into the normally dry section of the systems. This test will utilize an air or smoke flow testing methodology to demonstrate the nozzles remain free of obstruction. The event based frequency will ensure that it is performed following a maintenance activity that could have resulted in nozzle blockage. (Reference 4)

REFERENCES

1. FSAR, Section 6.2.1.1.5.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. FSAR, Section 6.2.2.2 Containment Heat Removal System Design
4. FSAR, Section 6.2.2.4 Testing and Inspection

BASES

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the FWLCS is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

With one FWLCS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE FWLCS subsystem is adequate to perform the leakage control function. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA, the amount of time available after the event for operator action to prevent exceeding this limit, the low probability of failure of the OPERABLE FWLCS subsystem, and the availability of the PCIVs.

B.1

With two FWLCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA, the availability of operator action, and the availability of the PCIVs.

C.1

If the inoperable FWLCS subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES (continued)

ACTIONS

C.1 (continued)

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

The allowed Completion Time is 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 3.6.1.8.1

Proper operation of the RHR jockey pump is required to verify the capability of the FWLCS to provide sufficient sealing water to each isolated section of each feedwater line to initiate and maintain the fluid seal for long term leakage control. The 31 day Frequency is considered adequate based on operating experience, on the procedural controls governing ECCS operation, and on the low probability of major changes in pump capability during the period.

REFERENCES

1. FSAR, Section 15.6.5.
2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

ACTIONS (continued)

C.1

If the MSIV LCS subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

The allowed Completion Times is 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 3.6.1.9.1

Each outboard MSIV LCS blower is operated for ≥ 15 minutes to verify OPERABILITY. The 31 day Frequency was developed considering the known reliability of the LCS blower and controls, the two subsystem redundancy, and the low probability of a significant degradation of the MSIV LCS subsystem occurring between surveillances and has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.9.2

Deleted

SR 3.6.1.9.3

A system functional test is performed to ensure that the MSIV LCS will operate through its operating sequence. This includes verifying that the automatic positioning of the valves and the operation of each interlock and timer are correct, that the blowers start and develop the required flow rate and the necessary vacuum. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 6.7.1.
2. FSAR, Section 15.6.5.
3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RHR Suppression Pool Cooling System satisfies Criterion 3 of the NRC Policy Statement.

LCO

During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the pump, two heat exchangers, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Cooling System OPERABILITY.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.

ACTIONS

A.1

With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

If one RHR suppression pool cooling subsystems inoperable and is not restored to OPERABLE status within the required Completion Time, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

(continued)

BASES

ACTIONS

B.1 (continued)

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, an establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

The allowed Completion Time is 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

With two RHR suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and the potential avoidance of a plant shutdown transient that could result in the need for the RHR suppression pool cooling subsystems to operate.

D.1 and D.2

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

RHR Suppression Pool Cooling 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 RHR suppression pool cooling subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling 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 Suppression Pool Cooling 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

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1 and SR 3.6.3.2.2

These SRs verify that there are no physical problems that could affect the igniter operation. Since the igniters are mechanically passive, they are not subject to mechanical failure. The only credible failures are loss of power or burnout. The verification that each required igniter is energized is performed by circuit current versus voltage measurement.

The Frequency of 184 days has been shown to be acceptable through operating experience because of the low failure occurrence, and provides assurance that hydrogen burn capability exists between the more rigorous 18 month Surveillances. Operating experience has shown these components usually pass the Surveillance when performed at a 184 day Frequency. Additionally, these surveillances must be performed every 92 days if four or more igniters in any division are inoperable. The 92 day Frequency was chosen, recognizing that the failure occurrence is higher than normal. Thus, decreasing the Frequency from 184 days to 92 days is a prudent measure, since only one more inoperable igniters (for a total of five) will result in an inoperable igniter division. SR 3.6.3.2.2 is modified by a Note that indicates that the Surveillance is not required to be performed until 92 days after four or more igniters in the division are discovered to be inoperable.

SR 3.6.3.2.3 and SR 3.6.3.2.4

These functional tests are performed every 18 months to verify system OPERABILITY. The current draw to develop a surface temperature of ≥ 1700EF is verified for igniters in inaccessible areas, e.g., in a high radiation area. Additionally, the surface temperature of each accessible igniter is measured to be ≥ 1700EF to demonstrate that a temperature sufficient for ignition is achieved. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

LCO (continued)	to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

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

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies in the primary or secondary containment. Due to radioactive decay, secondary containment is required to be OPERABLE only during that fuel movement involving the handling of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.3 and SR 3.6.4.1.4

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.3 verifies that the SGT System will rapidly establish and maintain a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary.

SR 3.6.4.1.4 demonstrates that each OPERABLE SGT subsystem can maintain a reduced pressure in the secondary containment sufficient to allow the secondary containment to be in thermal equilibrium at steady state conditions. The test criterion specified by SR 3.6.4.1.4 includes an allowance for building degradation between performances of the surveillance. This allowance represents additional building in-leakage of 115 scfm.

As discussed in B 3.6.4.2, the SGT System has the capacity to maintain secondary containment negative pressure assuming the failure of all non qualified lines 2 inches and smaller plus other analyzed failures. The number and size of these assumed failures can vary as penetrations are added or removed from the secondary containment boundary. To account for the absence of these assumed failures under test conditions the test criteria specified by SRs 3.6.4.1.3 and 3.6.4.1.4 are modified. To account for this additional in-leakage, the required vacuum level of SR 3.6.4.1.3 is modified to require that the secondary containment can be drawn down to ≥ 0.284 inches of vacuum water gauge in 180 seconds. For the same reason, the required vacuum level of SR 3.6.4.1.4 is also modified to require secondary containment be maintained ≥ 0.284 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 4000 cfm. The vacuum level used for these surveillances represents the minimum required to ensure that the integrity of the SGT system boundary will meet its design requirement of reaching (within 180 seconds) and maintaining ≥ 0.25 inches of vacuum water gauge following a postulated accident when combined with the assumed failures.

The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.3 and SR 3.6.4.1.4 (continued)

these SRs is to ensure that the SGT subsystem, being used for the test, functions as designed. There is a separate LCO 3.6.4.3 with Surveillance Requirements which serves the primary purpose of ensuring OPERABILITY of the SGT system. SRs 3.6.4.1.3 and 3.6.4.1.4 need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT system does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 15.6.5.

2. UFSAR, Section 15.7.4.

3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies in the primary or secondary containment. Due to radioactive decay, the SGT System is required to be OPERABLE only during fuel movement involving the handling of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS (continued)

B.1

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

C.1, C.2.1, and C.2.2

During movement of recently irradiated fuel assemblies in the primary or secondary containment or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem

(continued)

BASES

ACTIONS

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

should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing a significant amount of radioactive material to the secondary containment, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. This action should be chosen if the OPDRVs could be impacted by a loss of offsite power. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT System may not be capable of supporting the required radioactivity release control function. Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem from the control room for $\geq$ 15 continuous minutes ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

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

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.2 (continued)

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

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal.

The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.6 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. UFSAR, Section 6.5.3.
3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.1 (continued)

the safety analysis. This Surveillance is performed at least once every 10 years on a performance based frequency. This Frequency is consistent with the difficulty of performing the test, risk of high radiation exposure, and the remote possibility that sufficient component failures will occur such that the drywell bypass leakage limit will be exceeded. If during the performance of this required Surveillance the drywell bypass leakage rate is greater than the drywell bypass leakage limit the Surveillance Frequency is increased to every 48 months. If during the performance of the subsequent consecutive Surveillance the drywell bypass leakage rate is less than or equal to the drywell bypass leakage limit the 10 year Frequency may be resumed. If during the performance of two consecutive Surveillances the drywell bypass leakage is greater than the drywell bypass leakage limit the Surveillance Frequency is increased to at least once every 24 months. The 24 months Frequency is maintained until during the performance of two consecutive surveillances the drywell bypass leakage rate is less than or equal to the drywell bypass leakage limit, at which time the 10 year Frequency may be resumed. For two Surveillances to be considered consecutive the Surveillances must be performed at least 12 months apart.

Since the Frequency is performance based, the Frequency was concluded to be acceptable from a reliability standpoint (Ref. 3).

SR 3.6.5.1.2

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from performing its intended function. This SR ensures that drywell structural integrity is maintained. The Frequency was chosen so that the interior and exterior surfaces of the drywell can be inspected in conjunction with the inspections of the primary containment required by 10 CFR 50, Appendix J (Ref. 2). Due to the passive nature of the drywell structure, the specified Frequency is sufficient to identify

(continued)

BASES

ACTIONS

A.1 (continued)

maintained, and is considered a reasonable length of time needed to complete the Required Action.

A Note has been added to provide clarification that separate Condition entry is allowed for each vacuum relief subsystems not closed.

B.1 and C.1

With one or two drywell post-LOCA vacuum relief subsystems inoperable for reasons other than Condition A or one drywell purge vacuum relief subsystem inoperable for reasons other than Condition A, the inoperable subsystem(s) must be restored to OPERABLE status within 30 days. In these Conditions, the remaining OPERABLE vacuum relief subsystems are adequate to perform the depressurization mitigation function since two 10 inch lines remain available. The 30 day Completion Time takes into account the redundant capability afforded by the remaining subsystems, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

D.1

If one or two drywell post-LOCA vacuum relief subsystems are inoperable for reasons other than not being closed or one drywell purge vacuum relief subsystem is inoperable for reasons other than not being closed, and not restored within the provided Completion Time, the plant must be brought to a condition in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 2) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action D.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met.

(continued)

ACTIONS

D.1 (continued)

However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

The allowed Completion Time is 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 and F.1

With two drywell purge vacuum relief subsystems inoperable or with two drywell post-LOCA and one drywell purge vacuum relief subsystems inoperable for reasons other than Condition A, at least one inoperable subsystem must be restored to OPERABLE status within 72 hours. In these Conditions, only one 10 inch line remains available. The 72 hour Completion Time takes into account at least one vacuum relief subsystem is still OPERABLE, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

G.1, G.2, H1, and H.2

If the inoperable drywell vacuum relief subsystem(s) cannot be closed or restored to OPERABLE status within the required Completion Time, or if two drywell purge vacuum relief subsystems are inoperable for reasons other than Condition A and one or two drywell post-LOCA vacuum relief subsystem(s) are inoperable for reasons other than Condition A, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.6.1

Each vacuum breaker and its associated isolation valve is verified to be closed (except when being tested in accordance with SR 3.6.5.6.2 and SR 3.6.5.6.3 or when the vacuum breakers or isolation valves are performing their intended design function) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker or associated isolation valve position indication. The 7 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker or isolation valve status available to the plant personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. The first Note allows drywell vacuum breakers or isolation valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods are controlled by plant procedures and do not represent inoperable drywell vacuum breakers or isolation valves. A second Note is included to clarify that vacuum breakers or isolation valves open due to an actual differential pressure, are not considered as failing this SR.

SR 3.6.5.6.2

Each vacuum breaker and its associated isolation valve must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position.

This Surveillance includes a CHANNEL FUNCTIONAL TEST of the isolation valve differential pressure actuation instrumentation. This provides assurance that the safety analysis assumptions are valid. The Frequency of this Surveillance is in accordance with Inservice Test Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.6.3

Verification of the opening pressure differential is necessary to ensure that the safety analysis assumption that the vacuum breaker or isolation valve will open fully at a differential pressure of 1.0 psid is valid. This SR verifies that the pressure differential required to open the vacuum breakers is ≤ 1.0 psid and that the isolation valve differential pressure actuation instrumentation opens the valve at 0.0 to 1.0 psid for the drywell purge vacuum relief subsystem and -1.0 to 0.0 psid for the post-LOCA vacuum relief subsystems (drywe
ll minus containment). This SR includes a CHANNEL CALIBRATION of the isolation valve differential pressure actuation instrumentation. This Surveillance includes a calibration of the position indication as necessary. 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 violating the drywell boundary. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 6.2.

2. NEDC-32988-A, Revision 2, Technical Justification to Support Risk Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

ACTIONS (continued)

C.1

A low water level in the UHS basin indicates that the required 30 day water supply for the post LOCA cooling requirements may not be available. However, changes in water level for such a large volume are slowly occurring events and the degradation when discovered is unlikely to have significantly degraded the basin capability. The 72 hour Completion Time was developed taking into account the remaining capability of the UHS basin, the low probability that this inoperability occurring during the assumed maximum heat load conditions, and the low probability of a DBA occurring during this period.

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met the unit must be placed in a MODE in which overall plant risk is minimized. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action E.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

ACTIONS (continued)

F.1

If any both SSW subsystems are inoperable, or more than one of the UHS cooling towers have inoperable cooling tower fan(s), the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the UHS water source below the minimum level, the UHS basin must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

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 31 day Frequency is based on operating experience, the known reliability of the fan units, the redundancy available, and the low probability of significant degradation of the cooling tower fans occurring between Surveillances.

SR 3.7.1.3

Verifying the correct alignment for each required manual, power operated, and automatic valve in each SSW subsystem flow path provides assurance that the proper flow paths will exist for SSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.3 (continued)

This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

Isolation of the SSW System to components or systems does not necessarily affect the OPERABILITY of the SSW subsystem. As such, when all SSW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SSW subsystem needs to be evaluated to determine if it is still OPERABLE.

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

SR 3.7.1.4

This SR verifies that the automatic isolation valves of the SSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the SSW pump and cooling tower fans in each subsystem. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function.

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

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. UFSAR, Section 9.2.1.
3. UFSAR, Table 9.2-3.
4. UFSAR, Section 6.2.1.1.3.3.
5. UFSAR, Chapter 15.
6. UFSAR, Section 6.2.2.3.
7. UFSAR, Table 6.2-2.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

ACTIONS

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

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 or 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 protective 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 possible repair, and test most problems with the CRE boundary.

C.1

In MODE 1, 2, or 3, if the inoperable CRFA subsystem 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 overall plant risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS (continued)

C.1 (continued)

Required Action C.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

D.1, and D.2

During OPDRVs, if the inoperable CRFA subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CRFA subsystem may be placed in the isolation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes accident risk.

If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

E.1

If both CRFA subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CRE, the CRFA System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, the plant must be brought to a MODE in which the overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

(continued)

ACTIONS (continued)

E.1 (continued)

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action E.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

The allowed Completion Time is 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

Required Action F.1 is modified by a note indicating that LCO 3.0.3 does not apply. During OPDRVs, with two CRFA subsystems inoperable, or with one or more CRFA subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk.

If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that a subsystem in a standby mode starts from the control room on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each subsystem once every month provides an adequate check on this system. Operation for ≥ 15 continuous minutes demonstrates OPERABILITY of the system. Periodic operation ensures that blockages fan or motor failure, or excessive vibration can be detected for corrective action. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

SR 3.7.3.2

This SR verifies that the required CRFA testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, and minimum system flow rate. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.3.3

This SR verifies that each CRFA subsystem starts and operates and that the isolation valves close in ≤ 4 seconds on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.1 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.7.3.4

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.4 (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 B must be entered. Required Action B.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, which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 9). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 10). 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.

REFERENCES

1. FSAR, Section 6.5.1.
2. FSAR, Section 9.4.1.
3. FSAR, Chapter 6.
4. FSAR, Chapter 15.
5. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
6. Engineering Evaluation Request 95/6213, Engineering Evaluation Request Response Partial Response dated 12/18/95.
7. Amendment 145 to GGNS Operating License.

(continued)

BASES

REFERENCES (continued)

8. UFSAR, Section 9.5

9. NEI 99-03, Control Room Habitability Assessment, June 2001.

10. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML04300694).

BASES (continued)

LCO

Two independent and redundant subsystems of the Control Room AC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The Control Room AC System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls. The heating coils are not required for Control Room AC System OPERABILITY.

APPLICABILITY

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

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room AC System OPERABLE is not required in MODE 4 or 5, except during operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

<u>A.1</u>

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

(continued)

BASES

ACTIONS

B.1 and B.2

If both control room AC subsystems are inoperable, the Control Room AC System may not be capable of performing its intended function. Therefore, the control room area temperature is required to be monitored to ensure that temperature is being maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 7 days is allowed to restore a control room AC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained within limits, the low probability of an event occurring requiring control room isolation, and the availability of alternate cooling methods.

C.1

In MODE 1, 2, or 3, if the control room area temperature cannot be maintained less than or equal to 90°F or if the inoperable control room AC subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes overall plant risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 3) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

ACTIONS (continued)

E.1

During OPDRVs if the Required Action and associated Completion Time of Condition B is not met, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The 24 month Frequency is appropriate since significant degradation of the Control Room AC System is not expected over this time period.

REFERENCES

1. FSAR, Section 6.4.

2. FSAR, Section 9.4.1.

3. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES (continued)

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

B.1, and B.2

If the gross gamma activity rate is not restored to within the limits within the associated Completion Time, the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Action B.1 is to place the unit in a MODE in which overall plant risk is minimized. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 4) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing

(continued)

BASES

ACTIONS

B.1, and B.2 (continued)

inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 and 3.7.5.2

SR 3.7.5.2, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled include Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted as required by SR 3.7.5.1, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

SR 3.7.5.2 is modified by a Note indicating that the SR is not required to be performed until 31 days after any SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. FSAR, Section 15.7.1.
2. NUREG-0800.
3. 10 CFR 100.
4. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES (continued)

	B.1 If the Main Turbine Bypass System cannot be restored to OPERABLE status or the LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves are not applied, THERMAL POWER must be reduced to < 70% RTP. As discussed in the Applicability section, operation at <70% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass system is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.
SURVEILLANCE REQUIREMENTS	SR 3.7.7.1 Cycling each Main Turbine Bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint. SR 3.7.7.2 The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power.
REFERENCES	None

ACTIONS (continued)

B.3.1 and B.3.2

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

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the 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 time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. Although Condition B applies to a single inoperable DG, several Completion Times are specified for this Condition.

Division 3 DG

The first Completion Time applies to an inoperable Division 3 DG. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period. This Completion Time begins only "upon discovery of an inoperable Division 3 DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock

(continued)

BASES

ACTIONS

B.4 (continued)

for an inoperable Division 3 DG when Condition B may have already been entered for another equipment inoperability and is still in effect). As discussed in the APPLICABILITY SECTION a NOTE for Division 3 DG is provided allowing an exception to be taken to the 72 hour completion time. By declaring the HPCS System inoperable, the Division 3 DG allowed outage time could be extended up to 17 days (72 hours plus ECCS allowed outage time of 14 days). Use of this extension could be warranted for an unplanned DG inoperability and for voluntary planned maintenance or inspections. Any voluntary maintenance or inspection of the Division 3 DG shall be performed using a risk-informed process as required by 10CFR50.65(a)(4).

Additional contingencies are to be in place for the duration of the extended AOT duration (greater than 72 hours and up to 17 days) as follows:

1. Weather conditions will be evaluated prior to entering an extended DG allowed outage time for voluntary planned maintenance. An extended DG allowed outage time AOT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe conditions (hurricane, tropical storm, tornado, or snow/ice storm) that could significantly threaten grid stability during the planned outage time.

2. The condition of the offsite power supply and switchyard will be evaluated.

3. No elective maintenance will be scheduled within the switchyard that would challenge offsite power availability during the extended Division 3 DG allowed outage time.

4. Operating crews will be briefed on the DG work plan whenever the extended allowed outage time period is used, with consideration given to key procedural actions that would be required in the event of a loss of offsite power or station blackout.

(continued)

BASES

ACTIONS

B.4 (continued)

5. The RCIC high pressure injection system and the Division 1 and 2 DGs will not be taken out of service for planned maintenance while the Division 3 DG is out of service during the extended allowed outage time.

Division 1 and 2

The second Completion Time (14 days) applies to an inoperable Division 1 or Division 2 DG and is a risk-informed allowed outage time (AOT) based on a plant specific risk analysis. The extended AOT would typically be used for voluntary planned maintenance or inspections but can also be used for corrective maintenance.

However, use of the extended AOT for voluntary planned maintenance should be limited to once within an operating cycle (24 months) for each DG (Division 1 and Division 2).

Additional contingencies are to be in place for any extended AOT duration (greater than 72 hours and up to 14 days) as follows:

1. Weather conditions will be evaluated prior to entering an extended DG AOT for voluntary planned maintenance. An extended DG AOT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe conditions (hurricane, tropical storm, tornado, or snow/ice storm) that could significantly threaten grid stability during the planned outage time.

2. The condition of the offsite power supply and switchyard will be evaluated.

3. No elective maintenance will be scheduled within the switchyard that would challenge offsite power availability during the proposed extended DG AOT.

4. Operating crews will be briefed on the DG work plan whenever the extended AOT period is used, with consideration given to key procedural actions that would be required in the event of a loss of offsite power or station blackout. It is expected that the Division 3 DG can be cross-connected and ready to power required shutdown equipment on either Division 1 or Division 2 ESF bus within two hours of determining a need to cross-connect.

(continued)

ACTIONS

E.1 (continued)

remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1

Each sequencer is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer(s) is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Although loss of an ESF bus's sequencer potentially affects the major ESF systems in the division, a design basis event with the worst single failure would not result in a complete loss of onsite power function (DGs) and would be mitigated to some extent by the redundant onsite sources. In addition, operator action to start the DG affected by the inoperable sequencer and manually connect the required ESF loads to either the affected DG or an available offsite source represents a significant benefit justifying an extended Completion Time over the condition of one DG and one offsite circuit inoperable. The 24 hour Completion Time 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.

G.1

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the unit must be brought to MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action G.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment

(continued)

ACTIONS (continued)

G.1 (continued)

addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

H.1

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, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11).

Where the SRs discussed herein specify voltage and frequency tolerances, the minimum steady state output voltage of 3744 V and 4576 V respectively, are equal to ± 10% of the nominal 4160 V output voltage. The specified maximum and minimum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively, are equal to ± 2% of the 60 Hz nominal frequency. The specified steady state voltage and frequency ranges are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

(continued)

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.

SR 3.8.1.2 and SR 3.8.1.21

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (the Note for SR 3.8.1.21 and Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations for DG 11 and DG 12. For DG 13, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation.

In order to reduce stress and wear on diesel engines, the manufacturer recommends that the DGs be gradually accelerated to synchronous speed prior to loading. These modified start procedures are the intent of Note 3 of SR 3.8.1.2, which is only applicable when such procedures are used.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.21 (continued)

SR 3.8.1.21 requires that, at a 184 day frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The DG's ability to maintain the required voltage and frequency is tested by those SRs which require DG loading. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 5). The start requirements may not be applicable to 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the start requirements of SR 3.8.1.21 apply. Since SR 3.8.1.21 does require a 10 second start for each DG, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2. Similarly, the performance of SR 3.8.1.12 or SR 3.8.12.19 also satisfies the requirements of SR 3.8.1.2 and SR 3.8.1.21. In addition to the SR requirements, the time for the DG to reach steady state operation is periodically monitored (data is taken once per 6 months during the performance of SR 3.8.1.21) and the trend evaluated to identify degradation of governor and voltage regulator performance.

The DGs are started for this test by using one of the following signals: manual, simulated loss of offsite power by itself, simulated loss of offsite power in conjunction with an ESF actuation test signal, or an ESF actuation test signal by itself.

The 31 day Frequency for SR 3.8.1.2 is consistent with the industry guidelines for assessment of diesel generator performance (Ref. 14). The 184 day frequency for SR 3.8.1.21 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting 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 DG is connected to the offsite source.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

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

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for DG 11 is the 1314 kW low pressure core spray pump; for DG 12, the 686 kW residual heat removal (RHR) pump; and for DG 13 the 2411 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. This Surveillance may be accomplished by:

1) tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest load while paralleled to offsite power, or while solely supplying the bus, or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions:

Generator loss of excitation,
Generator reverse power,
High jacket water temperature,
Generator overcurrent with voltage restraint,
Bus underfrequency (DG 11 and DG 12 only),
Engine bearing temperature high (DG 11 and DG 12 only),
Low turbo charger oil pressure (DG 11 and DG 12 only),
Deleted
High lube oil temperature (DG 11 and DG 12 only),
Low lube oil pressure,
High crankcase pressure, and
Generator ground overcurrent (DG 11 and DG 12 only)

are bypassed on an ECCS initiation test signal. The non-critical trips are bypassed during DBAs and provide alarms on an abnormal engine conditions. These alarms provide the operator with necessary information to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

The SR is modified by a Note. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3) requires demonstration once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours - 22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. An exception to the loading requirements is made for DG 11 and DG 12. DG 11 and DG 12 are operated for 24 hours at a load greater than or equal to the maximum expected post accident load. Load carrying capability testing of the Transamerica Delaval Inc. (TDI) diesel generators (DG 11 and DG 12) has been limited to a load less than that which corresponds to 185 psig brake mean effective pressure (BMEP). Therefore, full load testing is performed at a load ≥ 5450 kW but < 5740 kW (Ref. 15). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Revision 3.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15, July 2, 1984.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
9. 10 CFR 50, Appendix A, GDC 18.
10. Regulatory Guide 1.137.
11. ANSI C84.1, 1982.
12. ASME, Boiler and Pressure Vessel Code, Section XI.
13. IEEE Standard 308.
14. NUMARC 87-00, Revision 1, August 1991.
15. Letter from E.G. Adensam to L.F. Dale, dated July 1984.
16. GNRI-96/00151, Amendment 124 to the Operating License.
17. Generic Letter 94-01, May 31, 1994.
18. GNRI-98/00016, Amendment 134 to the Operating License.
19. GNRI-2000/00065, Grand Gulf Nuclear Station, Unit 1 – Issuance of Amendment Re: Generic Changes to Improved Standard Technical Specifications, Amendment 142 to the Operating License.
20. ER-GG-2002-0466, Evaluation of P75 Standby Diesel Generators to Regulatory Guide 1.9, Rev. 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

The tests of fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s). The limits and applicable ASTM Standards for the tests listed in the Diesel Fuel Oil Testing Program of Specification 5.5.9 are to verify in accordance with the tests specified in ASTM D975 (Ref. 6) that the sample has a water and sediment content of ≤ 0.05 v/o, and a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes.

These tests are required every 92 days for fuel oil in the storage tanks and prior to addition for new fuel oil by Specification 5.5.9. Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed to establish an impurity level of < 2 mg/100 ml when tested in accordance with ASTM 2274-70 (Ref. 6). These additional analyses are required by Specification 5.5.9, Diesel Fuel Oil Testing Program, to be performed within 7 days following addition. The 7 day period is acceptable because the fuel oil properties of interest, even if not within stated

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in insolubles, mostly due to oxidation. The presence of insolubles does not mean that the fuel oil will not burn properly in a diesel engine. However, the insolubles can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

The Frequency of these Surveillances on the stored fuel oil takes into consideration fuel oil degradation trends indicating that overall fuel oil quality is unlikely to change between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. For DG 11 and DG 12 the starting air system is required to have a minimum capacity for one emergency DG start attempt above the air pressure interlock, and multiple manual start attempts below the interlock, without recharging the air start receivers. For DG 13 the starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers. The pressure specified in this SR reflects the value at which this can be accomplished, but is not so high as to result in failing the limit due to normal cycling of the recharge compressor.

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.

This Surveillance Requirement is met for a given division when one of the two starting air trains for the respective diesel generator meets the pressure specified in the Surveillance Requirement.

(continued)

ACTIONS

C.1 (continued)

If one of the required Division 1 or 2 DC electrical power subsystems is inoperable for reasons other than its associated battery charger inoperable, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 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

If a Division 1 or 2 DC electrical power subsystem is inoperable and not restored within the provided Completion Time, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 8) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action D.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES (continued)

ACTIONS

E.1

With the Division 3 DC electrical power subsystem inoperable for reasons other than its associated battery charger inoperable, the HPCS System may be incapable of performing its intended functions and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS — Operating."

F.1 and F.2

If the Division 3 DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time 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 charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. 9).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 10) and Regulatory Guide 1.129 (Ref. 11), 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. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance. For the purposes of this SR oxidation is not considered corrosion provided the resistance of the connection(s) is within limits.

The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the desired unit conditions to perform the Surveillance. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length (4 hours for Division 1 and Division 2 and 2 hours for Division 3) 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. 10) 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.

This SR is modified by two Notes. Note 1 allows the once per 60 months performance of SR 3.8.4.8 in lieu of SR 3.8.4.7. This substitution is acceptable because SR 3.8.4.8 represents a more severe test of battery capacity than SR 3.8.4.7. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. The Division 3 test may be performed in MODE 1, 2, or 3 in conjunction with HPCS system outages. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance 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.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 12). 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated when the battery capacity drops by more than 10% of rated capacity relative to its capacity on the previous performance test or is below 90% of the manufacturer's rating. These Frequencies are based on the recommendations in IEEE-450 (Ref. 9).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. The Division 3 test may be performed in MODE 1, 2, or 3 in conjunction with HPCS system outages. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. UFSAR, Section 8.3.2.
5. UFSAR, Chapter 6.
6. UFSAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974.
8. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
9. IEEE Standard 450, 1987.
10. Regulatory Guide 1.32, February 1977.
11. Regulatory Guide 1.129, December 1974.
12. IEEE Standard 485.

BASES

ACTIONS

B.1 (continued)

providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

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

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC division could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

C.1

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be bought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 5) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

C.1 (continued)

Required Action D.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, 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.

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

(continued)

BASES

ACTIONS (continued)

D.1

With the Division 3 electrical power distribution system inoperable, the Division 3 powered systems are not capable of performing their intended functions. Immediately declaring the high pressure core spray inoperable allows the ACTIONS of LCO 3.5.1, "ECCS — Operating," to apply appropriate limitations on continued reactor operation.

E.1

Condition E corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this 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.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

Meeting this Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical 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 and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.
4. UFSAR, Section 8.3.
5. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification. The ADHRS is included in the Specification to provide requirements for decay heat removal capability during an outage while the RHR System is out of service.

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level ≥ 22 ft 8 inches above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

The current requirements for decay heat removal are: In MODE 5 with no interface between vessel bulk coolant and spent fuel pool, the requirement is ≤ 155°F.

In MODE 5 with vessel bulk coolant interfacing with the spent fuel pool, the requirement is ≤ 140°F.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, two heat exchangers, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The required RHR shutdown cooling subsystem must have a OPERABLE diesel generator capable of supplying electrical power. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one decay heat removal subsystem (either RHR or ADHRS) can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation every 8 hours.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with irradiated fuel in the RPV and the water level ≥ 22 ft 8 inches above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.8.2

RHR Shutdown Cooling 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 shutdown cooling subsystem(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling 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 Shutdown Cooling 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 that the RHR Shutdown Cooling 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 Shutdown Cooling 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 subset 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.8.2 (continued)

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.

The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR Shutdown Cooling System piping and the procedural controls governing system operation.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Specification. The ADHRS is included in the Specification to provide requirements for decay heat removal capability during an outage while the RHR System is out of service.

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and the water level < 22 ft 8 inches above the RPV flange both RHR shutdown cooling subsystems must be OPERABLE, or the ADHRS may be substituted for one of the RHR subsystems.

The current requirements for decay heat removal are: In MODE 5 with no interface between vessel bulk coolant and spent fuel pool, the requirement is ≤ 155°F.

In MODE 5 with vessel bulk coolant interfacing with the spent fuel pool, the requirement is ≤ 140°F.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, two heat exchangers, valves, piping, instruments, and controls to ensure an OPERABLE flow path. An OPERABLE ADHRS consists of two pumps, two heat exchangers, valves, piping, instruments and controls to ensure an OPERABLE flow path. At least one of the required RHR shutdown cooling subsystems must have a OPERABLE diesel generator capable of supplying electrical power. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one decay heat removal subsystem (either RHR or ADHRS) can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to not be in operation every 8 hours.

APPLICABILITY

Two decay heat removal subsystems are required to be OPERABLE in MODE 5, with irradiated fuel in the RPV and the water level < 22 ft 8 inches above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5,

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.9.1

This Surveillance demonstrates that one RHR shutdown cooling subsystem or ADHRS is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

SR 3.9.9.2

RHR Shutdown Cooling 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 RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR Shutdown Cooling 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 Shutdown Cooling 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 that the RHR Shutdown Cooling 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.

BASES (continued)

RHR Shutdown Cooling 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 subset 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.

The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the RHR Shutdown Cooling System piping and the procedural controls governing system operation.

REFERENCES

AECM-90/0135, MAEC-90/0236, ER-GG-2007-0028.

Attachment 3

GNRO-2016/00024

Technical Requirements Manual Changes

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTIONAL UNIT	TRIP SETPOINT	RESPONSE TIMES (SECONDS)
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

NOTES

(a) This function is automatically bypassed at or below an Allowable Value of ≤ 32.0 RTP as measured by the power range neutron monitoring system.

(b) $T_L = T_X + T_C$; where:
T_L = Measured total response time of the RPS system instrumentation
T_X = Response time of the channel sensor
T_C = Measured response time of the logic circuit excluding the channel sensor

The given numerical value is the acceptance criterion for T_L.

In case the sensor is replaced or refurbished, a hydraulic response time test must be performed to determine a revised value for T_X. Note: In EPRI NP-7243, the failure modes and effects analysis (FMEA) for Rosemount differential pressure transmitters and pressure transmitters states, "For transmitters without the variable damping feature, no electronic failure modes were found that could affect the sensor response time." Therefore, for transmitters without variable damping, response time testing is not required following replacement of the electronics.

(c) Two-Loop Operation 0.58W + 57.1% RTP and ≤ 111.0% RTP
Single-Loop Operation: 0.58W + 34.3% RTP

(d) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(e) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures to confirm channel performance. The methodologies used to determine the as-found and as-left tolerances are specified in TRM Section 7.6.3.11.

(f) Neutron detectors, APRM channels, and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time is measured from activation of the 2-Out-Of-4 Voter output relay.

(g) The Trip Setpoint value for the OPRM Upscale Period-Based Detection algorithm is specified in the Core Operating Limits Report.

* See Bases Figure B 3.3.1.1

** Measure from start of turbine control valve fast closure.
\# Response time shall be measured from detector output or from the input of the first electronic component in the channel.

TABLE TR3.3.2.1-1

TECHNICAL SPECIFICATION CONTROL ROD BLOCK INSTRUMENTATION TRIP SETPOINTS

-----NOTES-----

The below Functions control when different ranges of Control Rod Block Instrumentation are in service.

FUNCTION	TRIP SETPOINT
1. Low Power Setpoint	26% RTP
2. High Power Setpoint	62% RTP

TABLE TR3.3.4.1-1

TECHNICAL SPECIFICATION END OF CYCLE RECIRCULATION PUMP TRIP INSTRUMENTATION
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTION	TRIP SETPOINT	RESPONSE TIMES (MILLISECONDS)
1. Turbine Stop Valve - Closure	≥ 40 psig (a)	≤ 190
2. Turbine Control Valve - Fast Closure	≥ 46.0 psig (a)	≤ 190

(a) This function is automatically bypassed at or below an Allowable Value of ≤ 32.0% RTP as measured by the power range neutron monitoring system.

TABLE TR3.3.6.1-1

TECHNICAL SPECIFICATION ISOLATION INSTRUMENTATION
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTION	TRIP SETPOINT	RESPONSE TIME (SECONDS)	Actuated Valve Groups
1. MAIN STEAM LINE ISOLATION			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	$T_L \leq 1.0$(f)	1
b. Main Steam Line Pressure - Low	≥ 849 psig	$T_L \leq 1.0$(f)	1
c. Main Steam Line Flow - High	≤ 252.5 psid	$T_L \leq 0.5$(f)	1
d. Condenser Vacuum - Low	≥ 9 inches Hg. Vacuum	NA	1
e. Main Steam Line Tunnel Temperature - High	≤ 185°F	NA	1
f. Manual Initiation	NA	NA	1,10
2. PRIMARY CONTAINMENT ISOLATION			
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	NA	6A,7,8,10
b. Drywell Pressure - High	≤ 1.23 psig	NA	6A,7
c. Reactor Vessel Water Level - Low Low Low, Level 1 (ECCS Division 1 and Division 2)	≥ -150.3 inches*	NA	5
d. Drywell Pressure-High (ECCS - Division 1 and Division 2)	≤ 1.39 psig	NA	5(e)
e. Reactor Vessel Water Level - Low Low, Level 2 (ECCS - Division 3)	≥ -41.6 inches*	NA	6B
f. Drywell Pressure - High (ECCS - Division 3)	≤ 1.39 psig	NA	6B

TABLE TR3.6.1.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

	SYSTEM AND VALVE NUMBER	PENETRATION NUMBER
2. Manual Isolation Valves#		
CTMT H_2 ANAL INST LINE ISOL VLV	E61-F598A-(A)	107B(O)(b)
CTMT H_2 ANAL INST LINE ISOL VLV	E61-F598B-(B)	107B(I)(b)
CTMT H_2 ANAL INST LINE ISOL VLV	E61-F598C-(A)	106E(O)(b)
CTMT H_2 ANAL INST LINE ISOL VLV	E61-F598D-(B)	106E(I)(b)
FLEX N_2 SUPPLY OB CTMT ISOL VLV	M41-F103	105D (O)
FLEX N_2 SUPPLY IB CTMT ISOL VLV	M41-F101	105D (I)
D/W INST LINE ISOL VLV	M71-F591A-A	101F(O)(b)
D/W INST LINE ISOL VLV	M71-F591B-B	102D(O)(b)
CTMT INST LINE ISOL VLV	M71-F592A-A	103D(O)(b)
CTMT INST LINE ISOL VLV	M71-F592B-B	104D(O)(b)
D/W INST LINE ISOL VLV	M71-F593-A	101C(O)(b)
SSW INL TO DRWL PURGE COMPR A (LOOP A)	P41-F159A-A	89(O)(b)(c)
SSW INL TO DRWL PURGE COMPR B (LOOP B)	P41-F159B-B	92(O)(b)(c)
SSW OTBD OUTL FM DRWL PURGE COMPR A (LOOP A)	P41-F160A-A	90(O)(b)(c)
SSW OTBD OUTL FM DRWL PURGE COMPR B (LOOP B)	P41-F160B-B	91(O)(b)(c)
SSW INBD OUTL FM DRWL PURGE COMPR A	P41-F168A-A	90(I)(b)(c)
SSW INBD OUTL FM DRWL PURGE COMPR B	P41-F168B-B	91(I)(b)(c)
CCW SPLY HDR TO CTMT	P42-F066-A	44(O)
CCW RTN HDR FM CTMT	P42-F067-A	45(O)
CCW RTN HDR FM CTMT	P42-F068-B	45(I)
AUX BLDG SLC WASTE STATION LINE	P48-F009	111C(I)
AUX BLDG SLC WASTE STATION LINE	P48-F010	111C(O)

TABLE TR3.6.1.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

	SYSTEM AND VALVE NUMBER	PENETRATION NUMBER
4. Test Connections		
AUX SEAL VALVE FOIL OUTLET DUCT TEST ISOL	M41-F042	34(O) (b)
AUX ISOL VLV F035 INLET DUCT TEST ISOL	M41-F051	35(O) (b)
EXH FILTER TRAIN E61-F057 INLET DUCT DRN	M41-F054	66(O) (b)
FLEX N_2 SUPPLY TEST CONNECTION VLV	M41-F105	105D (O)
T/C ISOL	M61-F009	40(I) (b)
T/C ISOL	M61-F010	82(I) (b)
CTMT CNDS XFER HDR T/C	P11-F095	56(O) (b)
TEST CONN	P11-F132	69(O) (b) (c)
TEST CONN	P11-F425	69(O) (b) (c)
"A" DRYWELL PURGE CPRSR CLR SUPPLY TEST CONN (LOOP "A")	P41-F163A	89(O) (b) (c)
"B" DRYWELL PURGE CPRSR CLR INL TEST CONN (LOOP "B")	P41-F163B	92(O) (b) (c)
CCW SPLY OTBD ISOL T/C	P42-F161	44(O) (b)
CCW RTN LINE T/C SHUTOFF	P42-F162	45(I) (b)
AUX BLDG FLR DR XFER TK PUMP BACK To SUPP POOL T/C	P45-F275	60(O) (b)
AUX BLDG FLR DR XFER TK PUMP BACK To SUPP POOL T/C	P45-F290	60(O) (b)
CTMT & DRYWELL SERV AIR HDR T/C	P52-F258	41(O) (b)
TEST CONNECTION	P53-F036	42(O) (b)
ADS MAKEUP ISOLATION	P53-F043	70(O) (b)

TABLE TR3.6.1.3-1 (Continued)

	SYSTEM AND VALVE NUMBER	PENETRATION NUMBER
4. Test Connections		
SUPPR POOL CLEANUP RETURN HDR TEST CONN	P60-F011	85(O) (b)
F010 T/C	P60-F034	85(O) (b)
AUX BLDG SEC LOOP SPLY OB T/C	P71-F232	38(O) (b)
AUX BLDG SEC LOOP OB T/C	P71-F246	39(O) (b)
TEST CONNECTION	P72-F167	37(O) (b)

(a) See the Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(b) Type C testing is not required.

(c) Hydrostatically tested with water to 1.10 P_a, 13.31 psig, when applicable.

(d) Hydrostatically tested by pressurizing system to 1.10 P_a, 13.31 psig, when applicable.

(e) Hydrostatically tested during system functional tests, when applicable.

(f) These valves have a design function as primary containment isolation when the inner airlock door is inoperable or during performance of airlock barrel testing or pnuematic tubing testing or at any time the inner airlock door/bulkhead is breached.

(g) Valve gagged closed.

The "-A, -B, -C, -(A), -(B), -(C)" designators on the valve numbers indicate associated electrical divisions.

---NOTE---
The following surveillance requirement applies to LCO 3.6.5.1. Failure to met this surveillance requirement requires entry into LCO 3.6.5.1.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR TR3.6.5.1.1	--------------------NOTE---------------------- Only required to be performed once after each closing. --- Verify seal leakage rate supports meeting the drywell bypass leakage limit (SR 3.6.5.1.1). For performance monitoring purposes the test administrative limit on seal leakage is ≤ 2 scfh when the gap between the door seals is pressurized to ≥ 12.1 psig.	72 hours
SR TR3.6.5.1.2	Verify drywell air lock leakage rate supports meeting the drywell bypass leakage limit (SR 3.6.5.1.1) by performing an air lock barrel leakage test at ≥ 3 psid. For performance monitoring purposes the test administrative limit on drywell air lock leakage is ≤ 2 scfh.	Prior to establishing drywell integrity when maintenance has been performed that could affect the air lock sealing capability.
SR TR3.6.5.1.3	--------------------NOTE---------------------- Not required to be performed until entry into MODE 2 or MODE 3 on the first unit startup from the ninth refueling outage. --- Perform a qualitative assessment of drywell leaktightness by observing the pressure change in the drywell resulting from operation of a drywell purge compressor(s).	Once per operating cycle

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR TR3.8.3.6	For each fuel oil storage tank: a. Drain the fuel oil; b. Remove the sediment; and c. Clean the tank. Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137, paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI, examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance. An extension to the surveillance is granted by ER 2003-0234-001. Div II may be inspected as late as March 2006. This does not apply to the ASME Section XI pressure test. An extension to the surveillance is granted by EC 61226 for the HPCS (Division III) inspection until June 2016.	10 years

6.10 BEYOND DESIGN BASES COMPONENTS

6.10.1 Spent Fuel Pool Level Instrumentation

LCO 6.10.1 The primary and back-up spent fuel pool level instruments shall be FUNCTIONAL

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The primary or back-up spent fuel pool level instrument does not meet the FUNCTIONAL requirements.	A.1 Restore spent fuel pool level instrument to FUNCTIONAL status.	90 days
B. Action A.1 completion time not met.	B.1 Implement compensatory measures.	Immediately
C. The primary and back-up spent fuel pool level instruments do not meet the FUNCTIONAL requirements.	C.1 Initiate actions to restore one of the channels of instrumentation. <u>AND</u> C.2 Implement compensatory measures.	24 hours 72 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 6.10.1	Perform CHANNEL FUNCTIONAL TEST.	Within 60 days of planned refueling outage if not performed in previous 12 months

6.10.2 Diverse and Flexible Coping Strategies (FLEX) Equipment

LCO 6.10.2 The FLEX equipment specified in Table 6.10.2-1 shall be FUNCTIONAL

APPLICABILITY: At all times.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each FLEX component.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more FLEX components specified in Table 6.10.2-1 does not meet the Column 2 requirements.	A.1 Restore the FLEX component to Column 2 FUNCTIONAL status.	90 days
B. Action A.1 completion time not met. OR One or more FLEX components specified in Table 6.10.2-1 does not meet the Column 2 requirements during a forecast site specific external event.	B.1 Supplement the FLEX component with alternate suitable equipment.	Immediately
C. One or more FLEX components specified in Table 6.10.2-1 does not meet the Column 1 requirements.	C.1 Initiate actions to restore site FLEX capability to Column 1 FUNCTIONAL status. AND C.2 Implement compensatory measures.	24 hours 72 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
None	N/A

TABLE TR 6.10.2-1

FLEX EQUIPMENT THAT DIRECTLY PERFORMS A FLEX MITIGATION STRATEGY FOR THE KEY SAFETY FUNCTIONS

COMPONENT	NUMBER REQUIRED TO SUPPORT FLEX STRATEGIES (Column 1)	NUMBER TO MEET FLEX SPARE REQUIREMENTS (Column 2)
FLEX Battery Charger Diesel Generator(1) (FLEXS009 / FLEXS010)	1	2
FLEX Makeup Pump (FLEXC001 / FLEXC002)	1	2
Hydrogen Igniter Diesel Generator(1) (FLEXS011 / FLEXS022)	1	2

(1) Component FUNCTIONALITY is NOT required if reactor pressure vessel is defueled.

6.10.3 FLEX Fluid and Electrical Connection Components

LCO 6.10.3 The FLEX Fluid and Electrical Connection Components Required to Implement the FLEX Strategy when the FLEX Equipment is connected at the point specified in Table 6.10.3-1 shall be FUNCTIONAL:

APPLICABILITY: At all times.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each FLEX connection.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The Primary or Secondary Connection for one or more Safety Functions / FLEX components specified in Table 6.10.3-1 is not FUNCTIONAL.	A.1 Restore the FLEX Connection to FUNCTIONAL status.	90 days
B. Action A.1 completion time not met.	B.1 Supplement the FLEX Connection with an additional Connection that meets the requirements of NEI 12-06 including diversity.[a]	Immediately
C. The Primary and Secondary Connection for one or more Safety Functions/FLEX components specified in Table 6.10.3-1 are not FUNCTIONAL.	C.1 Initiate actions to restore site FLEX capability <u>AND</u> C.2 Implement compensatory measures	24 hours 72 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
None	N/A

(a) The portable fluid connections for core and SFP cooling functions are expected to have a primary and an alternate connection or delivery point. Electrical diversity can be accomplished by providing a primary and alternate method to repower key equipment and instruments utilized in FLEX strategies.

TABLE TR 6.10.3-1

FLEX CONNECTIONS THAT DIRECTLY PERFORM A FLEX MITIGATION STRATEGY FOR THE KEY SAFETY FUNCTIONS

SAFETY FUNCTION/FLEX COMPONENT	PRIMARY CONNECTION POINT	SECONDARY CONNECTION POINT
Maintain Core Cooling / FLEX Battery Charger Diesel Generator(1)	N1R20P016	N1R20P017
Maintain Core Cooling / FLEX Makeup Pump(1)	N1P11F438	N1P11F445
Maintain SFP Cooling / FLEX Makeup Pump	Hose Routed to Pool or Spray Monitor	Q1G41F247A
Maintain Containment / Hydrogen Igniter Diesel Generator(1)	1BPZ2A	1BPZ2B

(1) Connection FUNCTIONALITY is NOT required if reactor pressure vessel is defueled.

6.10.4 Reactor Core Isolation Cooling (RCIC) Suction to Upper Containment Pool (UCP) Cross-Tie

LCO 6.10.4 The RCIC Suction to UCP Cross-Tie System including the following components shall be OPERABLE:

a. Control Panel 1H22P003
b. 1G41F201 (valve and actuator).

APPLICABILITY: MODES 1, 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC Suction to UCP System nonfunctional.	A.1 Initiate actions to restore site FLEX capability.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
None	N/A

6.10.5 FLEX Containment Vent System

LCO 6.10.5 The FLEX Containment Vent System including the following components shall be FUNCTIONAL:

a. Control Panel M41P001
b. Valve Operators capable of opening 1M41F034, 1M41F035, 1M41F036, 1M41F037, and 1M41F100
c. A minimum of 4 Nitrogen Bottles pressurized to > 2000 psig.

APPLICABILITY: MODES 1, 2 and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. FLEX Containment Vent System nonfunctional.	A.1 Initiate actions to restore site FLEX capability	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
None	N/A

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. A required fire detection instrument inoperable.	B.2 Restore the minimum number of instruments to OPERABLE status.	14 days
C. Required Action B and Associated Completion Time not met.	C.1 Initiate action to prepare an appropriate deficiency document.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 6.2.1.1	Perform a CHANNEL FUNCTIONAL TEST on required fire detection instruments which are accessible during unit operation.	18 months
SR 6.2.1.2	------------------NOTE------------------ Only required to be performed prior to entering MODE 2 or 3 from MODE 4 when in MODE 4 for ≥ 24 hours. -- Perform a CHANNEL FUNCTIONAL TEST on required fire detection instruments which are not accessible during unit operation.	24 months
SR 6.2.1.3	The NFPA Standard 72D supervised circuits supervision associated with the detector alarms of each required fire detection instruments that are accessible during unit operation shall be demonstrated OPERABLE.	18 months
SR 6.2.1.4	The NFPA Standard 72D supervised circuits Supervision associated with the detector alarms of each required fire detection instruments which are not accessible during unit operation shall be demonstrated OPERABLE.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 6.2.4.3	-----------------------NOTE----------------------- Actual CO2 release, electro-thermal link burning, and differential pressure valve opening may be excluded -- Verify that the system valves and associated ventilation system fire damper logic actuates automatically or manually, as applicable, upon receipt of a simulated actuation signal.	18 months
SR 6.2.4.4	Verify flow from each nozzle by performance of a "Puff Test"	18 months
SR 6.2.4.5	For each ventilation system fire damper that is accessible during unit operation, exercise each ventilation system fire damper to the closed position and verify the dampers move freely.	18 months
SR 6.2.4.6	For each ventilation system fire damper that is not accessible during unit operation, exercise each ventilation system fire damper to the closed position and verify the dampers move freely.	24 months

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 6.2.5.1	------------------------NOTE------------------------ Hazard area selector valves F497G and F497H may be excluded. -- Verify that each required manual, power operated or automatic valve in the flow path is in its correct position	31 days
SR 6.2.5.2	Verify Halon storage tank weight ≥ 95% of full charge weight and ≥ 90% of full charge pressure.	18 months
SR 6.2.5.3	------------------------NOTE------------------------ Actual Halon release, Halon bottle initiator valve actuation, and electro-thermal link burning may be excluded. -- Verify that the system, including associated ventilation system fire damper logic, actuates automatically upon receipt of a simulated actuation signal.	18 months
SR 6.2.5.4	Perform a flow test through headers and nozzles to assure no blockage.	18 months
SR 6.2.5.5	For each ventilation system fire damper that is accessible during unit operation exercise each ventilation system fire damper to the closed position and verify the dampers move freely.	18 month
SR 6.2.5.6	For each ventilation system fire damper that is not accessible during unit operation, exercise each ventilation system fire damper to the closed position and verify the dampers move freely.	24 months

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 6.2.6.1	Visually inspect each fire hose station accessible during plant operation to assure all required equipment is at the station.	31 days
SR 6.2.6.2	Visually inspect each fire hose station not accessible during plant operation to assure all required equipment is at the station.	18 months
SR 6.2.6.3	Remove each hose for inspection; inspect all gaskets and replace any degraded gaskets in the couplings; and re-rack each hose.	18 months
SR 6.2.6.4	Partially open each hose station valve to verify valve OPERABILITY and no flow blockage.	36 months
SR 6.2.6.5	Conduct a hose hydrostatic test on each fire hose at a pressure of $\geq$ 150 psig or $\geq$ 50 psig above the maximum fire main operating pressure, whichever is greater.	Not exceeding 5 years after the date of manufacture and every 3 years thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 6.2.8.1	Verify that required fire doors with automatic hold-open and release mechanisms are free of obstructions.	24 hours
SR 6.2.8.2	Verify that each required unlocked fire door without electrical supervision is closed.	24 hours
SR 6.2.8.3	Verify that each required locked-closed fire door is closed.	7 days
SR 6.2.8.4	Perform a CHANNEL FUNCTIONAL TEST for each required electrically supervised fire door.	31 days
SR 6.2.8.5	Inspect the release, closing mechanism and latches on the required fire doors with automatic hold-open and release mechanisms.	6 months
SR 6.2.8.6	Perform a functional test on the required fire doors with automatic hold-open and release mechanisms.	18 months
SR 6.2.8.7	For components that are accessible during normal unit operation perform a visual inspection of: a. the exposed surfaces of each required fire rated assembly, and b. each required fire window and fire damper and associated hardware.	18 months
SR 6.2.8.8	Perform a visual inspection of at least 10 percent of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10 percent of each type of sealed penetration shall be made. This inspection process shall continue until a 10 percent sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected so that each penetration seal will be inspected at least once per 15 years.	18 months
SR 6.2.8.9	For all components that are not accessible during normal unit operation perform a visual inspection of: a. the exposed surfaces of each required fire rated assembly, and b. each required fire window and fire damper and associated hardware.	24 months

6.3 INSTRUMENTATION

6.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

LCO 6.3.8 One turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

--NOTES--

1. Separate Condition entry is allowed for each high pressure or low pressure steam line.

2. LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One stop valve or control valve per steam line inoperable.	A.1 Enter LCO 6.0.1.	Immediately
B. One of the required turbine overspeed protection systems inoperable for reasons other than Condition A.	B.1 Enter LCO 6.0.1.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--

The provisions of SR 3.0.4 are not applicable.

	SURVEILLANCE	FREQUENCY
SR 6.3.8.1	Cycle each of the following valves through at least one complete cycle from the running position using the manual test or Automatic Turbine Tester (ATT): 1) Four high pressure turbine stop valves, 2) Four high pressure turbine control valves, 3) Six low pressure turbine stop valves, and 4) Six low pressure turbine control valves.	92 days EC 57666 approves a one time extension of surveillance 6.3.8.1. This one time Due Date extension is to 2/21/2016. The testing frequency will return to the 92 day interval following this one time extension.
SR 6.3.8.2	Test the two mechanical overspeed devices using the Automatic Turbine Tester or manual test.	8 weeks
SR 6.3.8.3	Disassemble at least one of each type of the following valves and performing a visual and surface inspection of valve seats, disks and stems and verifying no unacceptable flaws. If unacceptable flaws are found, all other valves of that type shall be inspected. 1) Four high pressure turbine stop valves, 2) Four high pressure turbine control valves, 3) Six low pressure turbine stop valves, and 4) Six low pressure turbine control valves.	48 months

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 6.3.2.1	Perform a CHANNEL CHECK on required triaxial strong motion accelerometers.	92 days
SR 6.3.2.2	Perform a CHANNEL FUNCTIONAL TEST on required triaxial strong motion accelerometers.	6 months
SR 6.3.2.3	Perform a CHANNEL CALIBRATION on all required seismic monitoring instruments.	24 months
SR 6.3.2.4	-----------------------NOTE----------------------- Not required to be performed until instrument is actuated by a seismic event ≥ 0.01 g. --	
	Restore to operable.	24 hours
	AND	
	Perform a CHANNEL CALIBRATION.	5 days
	AND	
	Initiate action to prepare and submit a Special Report to the Commission within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.	Immediately

TABLE 6.3.2-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS		MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1.	Triaxial Strong Motion Accelerometer		
a.	Containment foundation*	0.001 to 2.0g	1
b.	Drywell*	0.001 to 2.0g	1
c.	SGTS Filter Train	0.001 to 2.0g	1
d.	SSW Pump House A	0.001 to 2.0g	1
e.	Free Field	0.001 to 2.0g	1
f.	Reactor Piping Support	0.001 to 2.0g	1
2.	Triaxial Peak Recording Accelerograph		
a.	Containment Dome	0.01 to 2.0g	1
b.	Auxiliary Building Foundation	0.01 to 2.0g	1
c.	Diesel Generator 11	0.01 to 2.0g	1
d.	Control Building Foundation	0.01 to 2.0g	1
e.	Control Room	0.01 to 2.0g	1
f.	Reactor Vessel Support	0.01 to 2.0g	1
g.	SSW Pump House B	0.01 to 2.0g	1

*With control room annunciation.

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required Type B Room Cooler inoperable. <u>OR</u> Two or more required Room Coolers inoperable.	C.1 Verify the associated SSW subsystem is inoperable and LCO 3.0.6 is applicable. <u>OR</u> C.2 Declare affected cooled equipment inoperable <u>OR</u> C.3 Establish room cooling by an alternate means which has been approved via 10 CFR 50.59. <u>OR</u> C.4 Declare affected AC and DC distribution subsystems inoperable	Immediately Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

--- NOTE ---

The applicable Surveillance Requirements are those required to support SSW System heat removel capability.

TABLE 6.7.3-1

AREA TEMPERATURE MONITORING

AREA	TEMPERATURE LIMIT (°F)
a. Containment	
Inside Drywell	150
CRD Cavity	185
Outside Drywell	105
RWCU HX Room Valve Nest Area	120
Steam Tunnel	125
b. Auxiliary Building	
General	104
ECCS Rooms	150
ESF Electrical Rooms	104
Steam Tunnel	125
c. Control Building	
ESF Switchgear and Battery Rooms	104
Control Room	90
d. Diesel Generator Rooms	120
e. SSW Pumphouse	104*

*For this area, the limit shall be the greater of 104°F or outside ambient temperature plus 10°F, not to exceed 111°F.

g. The following are clarifications of the required testing frequency and other requirements:

   1. Deleted

   2. At least once per 18 months, during plant or system shutdown, demonstrate the SBLC pump relief valve opens within 3% of the system design pressure and verify that the SBLC relief valve does not actuate during recirculation to the test tank.

7.6.3.4 FILTER TESTING PROGRAM

In addition to the requirements of Technical Specification 5.5.7 the following requirements apply to the filter testing program:

a. The testing requirements of Technical Specification 5.5.7.a will be performed at least once per 24 months or (1) after any structural maintenance on the HEPA filter (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem, or (3) after each complete or partial replacement of a HEPA filter bank.

b. The testing requirements of Technical Specification 5.5.7.b will be performed at least once per 24 months or (1) after any structural maintenance on the charcoal adsorber housings, (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem, or (3) following each complete or partial replacement of a charcoal adsorber bank.

c. The testing requirements of Technical Specification 5.5.7.c will be performed at least once per 24 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem, or (3) every 720 hours of charcoal adsorber operation. The representative carbon sample will be tested within 31 days following removal.

d. The testing requirements of Technical Specification 5.5.7.d will be performed at least once per 24 months.

e. The testing requirements of Technical Specification 5.5.7.e will be performed at least once per 24 months.

B 6.3.5 LOOSE PART DETECTION SYSTEM - Deleted

B 6.3.6 MAIN CONDENSER OFFGAS TREATMENT SYSTEM - EXPLOSIVE GAS MONITORING SYSTEM INSTRUMENTATION

The explosive gas monitoring system instrumentation of the main condenser off gas treatment system is provided to monitor the concentrations of potentially explosive gas mixtures in the main condenser off gas treatment system. This instrumentation is calibrated in accordance with plant procedures.

B 6.3.8 TURBINE OVERSPEED PROTECTION

This specification is provided to ensure that the turbine overspeed protection instrumentation and the turbine speed control valves are FUNCTIONAL and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety-related components, equipment or structures. For any valves which become NON-FUNCTIONAL UFSAR section 3.5.1.3 shall be reviewed for affect on the probability analysis to ensure risk is appropriately addressed. The turbine overspeed speed protection system is comprised of a mechanical and electrical overspeed protection devices. The mechanical overspeed device is the backup to the electrical overspeed device (reference UFSAR Chapter 10.2.2.5.4, Overspeed Protection). Limiting Condition For Operation is used to control risk and ensure timely corrective actions.

B 6.3.12 Ultrasonic Flowmeter - Deleted

B 6.3.12 Deleted

B 6.4.1 CHEMISTRY

The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel. The effect of chlorides is not as great when the oxygen concentration in the coolant is low, thus the 0.2 ppm limit on chlorides is permitted during power operation. During shutdown and refueling operations, the temperature necessary for stress corrosion to occur is not present so a 0.5 ppm concentration of chlorides is not considered harmful during these periods.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of an abnormal condition. When the conductivity is within limits, the pH, chlorides and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

The surveillance requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

B 6.7.1 ROOM COOLERS

The Type A and B Room Coolers ensure that the safety-related equipment supported by the coolers will not be subjected to temperatures in excess of their environmental qualification temperatures. Loss of room coolers as described in TRM 6.7.1 affects the operability of the systems supported by the inoperable room cooler. In these cases the most limiting condition of operation needs to be assessed, specifically the conditions of LCO 3.0.6. If alternate cooling is required to be established, approval of the alternate cooling methodology must be approved through the 50.59 evaluation process.

B 6.7.2 SEALED SOURCE CONTAMINATION

The limitation on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation-monitoring or boron measuring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

B 6.7.3 AREA TEMPERATURE MONITORING

The area temperature limitations ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excessive temperatures may degrade equipment and can cause loss of its OPERABILITY. The temperature limits include allowance for instrument error.

B 6.7.4 SPENT FUEL STORAGE POOL TEMPERATURE

The temperature limit in the spent fuel storage pool ensures proper pool cooling to maintain building accessibility and prevents unacceptable radiological releases particularly during those times of increased fuel pool cooling heat loads, such as a fuel core offload, when supplemental fuel pool cooling utilizing the RHR system is required.

B 6.7.5 FLOOD PROTECTION

The required stability of the downstream slope of the access road embankment and the limit on the maximum permissible blockage of Culvert No. 1 are intended to ensure that Culvert No. 1 is always functional, because, in the event the culvert is blocked, flooding of the plant and safety-related facilities could occur during a PMP event.

B 6.7.6 STRUCTURAL INTEGRITY

The inspection programs for ASME Code Class 1, 2, and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant.

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1977 Edition, and Addenda through Summer 1978.

The inservice inspection program for ASME Code Class 1, 2 and 3 components will be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the NRC pursuant to 10 CFR Part 50.55a(g)(6)(i).

B 6.8.1 PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary containment electrical penetrations and penetration conductors are protected by either de-energizing circuits not required during reactor operation or demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers by periodic surveillance.

The surveillance requirements applicable to lower voltage circuit breakers provide assurance of breaker reliability by testing at least one representative sample of each manufacturer's brand of circuit breaker. Each manufacturer's molded case and metal case circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

B 6.8.2 MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

The OPERABILITY or bypassing of the motor operated valve thermal overload protection continuously or under accident conditions by integral bypass devices ensures that the thermal overload protection during accident conditions will not prevent safety-related valves from performing their function. The surveillance requirements for demonstrating the OPERABILITY or bypassing of the thermal overload protection continuously and or during accident conditions are in accordance with Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor Operated Valves," Revision 1, March 1977.

B 6.9.1 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

B 6.9.2 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

B 6.9.3 REFUELING PLATFORM

The OPERABILITY requirements in conjunction with 6.9.4 and 6.9.5 ensure that:

1. only the main hoist of the refueling platform or the main hoist of the fuel handling platform will be used for handling fuel assemblies within the reactor pressure vessel,
2. platform hoists have sufficient load capacity for handling fuel assemblies and/or control rods,
3. the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and
4. a fuel bundle is protected from excessive lifting force in the event it becomes stuck during lifting operations.

B 6.9.4 AUXILIARY PLATFORM

See the discussion for 6.9.3.

B 6.9.5 FUEL HANDLING PLATFORM

See the discussion for 6.9.3.

B 6.9.6 CRANE TRAVEL - SPENT FUEL AND UPPER CONTAINMENT FUEL STORAGE POOL

The restriction on the movement of a non-fuel load defined as a heavy load in NUREG-0612 over fuel assemblies in the storage pools ensures that in the event this load is dropped:

1. the activity release will be bounded by the activity release in the safety analysis, and
2. any possible distortion of fuel in the storage racks will not result in a critical array.

B 6.9.7 HORIZONTAL FUEL TRANSFER SYSTEM

The purpose of the horizontal fuel transfer system specification is to control personnel access to those potentially high radiation areas immediately adjacent to the system and to assure safe operation of the system.

B 6.10.1 SPENT FUEL POOL LEVEL INSTRUMENTATION

NRC Order EA-12-051, "Issuance of Order to Modify Licenses with regard to Reliable Spent Fuel Pool Instrumentation," required plants to provide reliable SFP instrumentation in partial response to the March 2011 Fukushima accident. NRC interim staff guidance JLD-ISG-2012-03 directly implements the requirements contained in Order EA-12-051and allows for the use of alternate suitable equipment or supplemental personnel as compensatory measures.

B 6.10.2 DIVERSE AND FLEXIBLE COPING STRATEGIES (FLEX) EQUIPMENT

NRC Order EA-12-049, "Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for beyond-Design-Basis External Events," required plants to provide mitigating strategies and associated equipment for an extended loss of power following design basis events or conditions. This was in partial response to the March 2011 Fukushima accident. TRM Section 6.10.2 directly implements the requirements of Order EA-12-049 and allows that a hurricane is an example of a forecast site specific external event. It also allows for the use of alternate suitable equipment or supplemental personnel as examples of compensatory measures.

B 6.10.3 FLEX FLUID AND ELECTRICAL CONNECTION COMPONENTS

NRC Order EA-12-049, "Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for beyond Design Basis External Events," required plants to provide mitigating strategies and associated equipment for an extended loss of power following design basis events or conditions. This was in partial response to the March 2011 Fukushima accident. TRM Section 6.10.3 directly implements the requirements of NRC Order EA- 12-049 and allows for the use of alternate suitable equipment or supplemental personnel are examples of compensatory measures.

B 6.10.4 RCIC SUCTION TO UPPER CONTAINMENT POOL (UCP) CROSS-TIE

According to the Beyond Design Basis External Event (BDBEE) analysis, when the suppression pool temperature reaches approximately 170°F (in about 3 hours after the initial BDBEE) the RCIC suction will be locally manually aligned to the upper containment pool in order to maintain a cool source of cooling water supply to the RCIC pump and turbine as well as to maintain net positive suction head for the RCIC pump without credit for containment overpressure.

B 6.10.5 FLEX CONTAINMENT VENT SYSTEM

According to the Beyond Design Basis External Event (BDBEE) analysis, before the suppression pool temperature exceeds approximately 190°F, (in about 4 hours after the initial BDBEE) the suppression pool / containment will be vented to atmosphere to limit containment pressurization and minimize the containment temperature increase.

B 7.6.3.3 INSERVICE INSPECTION AND TESTING PROGRAMS

This specification establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a. These requirements apply except when relief has been provided in writing by the Commission.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the technical specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the technical specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable addenda. The requirements of the technical specifications to perform surveillance activities before entry into a MODE or other specified condition takes precedence over the ASME Boiler and Pressure Vessel Code provision that allows pumps to be tested up to one week after return to normal operation. The technical specification definition of OPERABLE does not allow a grace period before a component, which is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code provision that allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

B 7.6.3.10 SNUBBERS

The snubber testing and visual inspection program will be performed in accordance with ASME OM Code Subsection ISTD and applicable addenda as required by 10 CFR 50.55a.

TABLE OF CONTENTS

TABLE OF CONTENTS

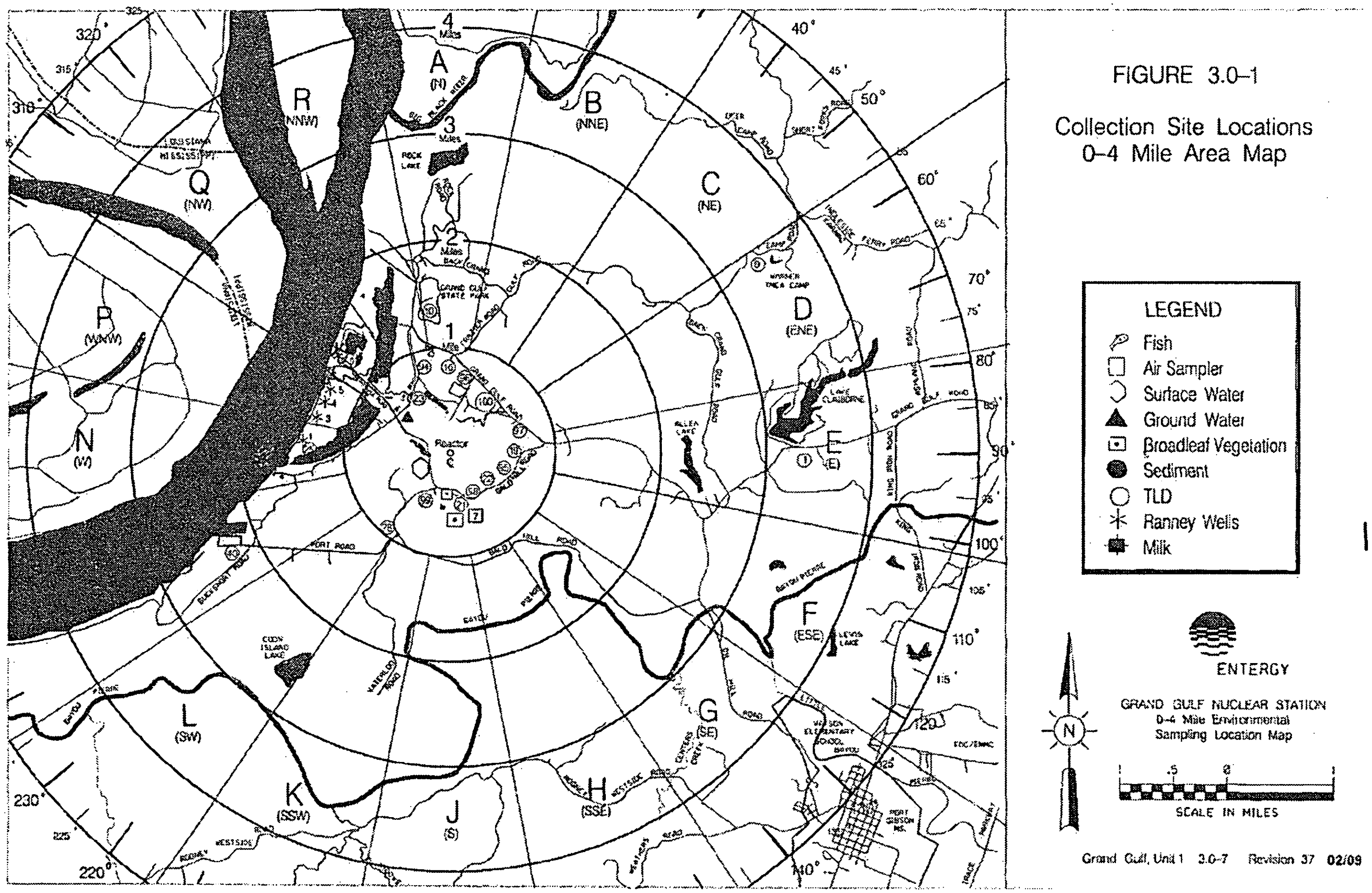
Attachment 4

GNRO-2016/00024

Offsite Dose Calculation Manual Changes

Figure 3.0-1
Collection Site Locations, 0-4 Mile Area Map

LBDCR # 2011002



ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.2 and referenced in Table 6.3.9-1.	B.1 At least two independent samples are analyzed in accordance with LCO 6.11.1.	Prior to each release.
	AND	
	B.2 At least two technically qualified members of the Facility Staff independently verify the release rate calculations and discharge path valve line-up.	Prior to each release.
	AND	
	B.3 Restore channel to operable.	14 days
C. As required by Required Action A.2 and referenced in Table 6.3.9-1.	C.1 Estimate the flow rate for the affected pathway during actual releases. Pump curves or discharge canal flow monitor may be used to estimate flow.	Once per 4 hours
	AND	
	C.2 Restore channel to operable.	30 days
D. Required Action and associated Completion Time of Condition B not met.	D.1 Suspend release of radiactive effluent via affected pathway.	Immediately
	AND	
	D.2 Initiate action to explain why this inoperability was not corrected in a timely manner in the next Annual Radioactive Effluent Release Report.	Immediately
E. Required Action and associated Completion Time of Condition C not met.	E.1 Initiate action to explain why this inoperability was not corrected in a timely manner in the next Annual Radioactive Effluent Release Report.	Immediately

Attachment 6

GNRO-2016/00024

GEH Affidavit

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, Lisa K. Schichlein, state as follows:

(1) I am a Senior Project Manager, NPP/Services Licensing, Regulatory Affairs, GE-Hitachi Nuclear Energy Americas LLC (GEH), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH proprietary report NEDC-33868P, "Entergy Operations, Inc. Grand Gulf Nuclear Station Pressure and Temperature Limits Report (PTLR) Up to 54 Effective Full-Power Years," Revision 0, dated June 2015. GEH proprietary information in NEDC-33868P is identified by a dotted underline placed within double square brackets. [[This sentence is an example.{3}]]. GEH proprietary information in figures and large objects is identified by double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the *Freedom of Information Act* ("FOIA"), 5 U.S.C. §552(b)(4), and the *Trade Secrets Act*, 18 U.S.C. §1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualifies under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975 F.2d 871 (D.C. Cir. 1992), and Public Citizen Health Research Group v. FDA, 704 F.2d 1280 (D.C. Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without a license from GEH constitutes a competitive economic advantage over other companies;

b. Information that, if used by a competitor, would reduce its expenditure of resources or improve its competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, resulting in potential products to GEH;

d. Information that discloses trade secret or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions for proprietary or confidentiality agreements or both that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary and/or confidentiality agreements.

(8) The information identified in paragraph (2) is classified as proprietary because it contains the detailed GEH methodology for pressure-temperature curve analysis for the GEH Boiling Water Reactor (BWR). These methods, techniques, and data along with their application to the design, modification, and analyses associated with the pressure-temperature curves were achieved at a significant cost to GEH.

The development of the evaluation processes along with the interpretation and application of the analytical results is derived from the extensive experience databases that constitute a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and

analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 30th day of June 2015.

Lisa K Schichlein

Lisa K. Schichlein
Senior Project Manager, NPP/Services Licensing
Regulatory Affairs
GE-Hitachi Nuclear Energy Americas LLC
3901 Castle Hayne Road
Wilmington, NC 28401
Lisa.Schichlein@ge.com

Attachment 1

ELECTRIC POWER RESEARCH INSTITUTE

NEIL WILMSHURST
Vice President and
Chief Nuclear Officer

Ref. EPRI Project Number 669

June 24, 2015

Document Control Desk
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Subject: Request for Withholding of the following Proprietary Information Included in:

Entergy Operations, Inc. Grand Gulf Nuclear Station Submittal to the NRC on "Pressure and Temperature Limits Report (PTLR) Up to 54 Effective Full-Power Years" Included in GE Hitachi Nuclear Energy Report: NEDC-33868P, Revision 0, June 2015

To Whom It May Concern:

This is a request under 10 C.F.R. §2.390(a)(4) that the U.S. Nuclear Regulatory Commission ("NRC") withhold from public disclosure the report identified in the enclosed Affidavit consisting of the proprietary information owned by Electric Power Research Institute, Inc. ("EPRI") identified in the attached report. Proprietary and non-proprietary versions of the Report and the Affidavit in support of this request are enclosed.

EPRI desires to disclose the Proprietary Information in confidence to assist the NRC review of the enclosed submittal to the NRC by Entergy. The Proprietary Information is not to be divulged to anyone outside of the NRC or to any of its contractors, nor shall any copies be made of the Proprietary Information provided herein. EPRI welcomes any discussions and/or questions relating to the information enclosed.

If you have any questions about the legal aspects of this request for withholding, please do not hesitate to contact me at (704) 595-2732. Questions on the content of the Report should be directed to Andy McGehee of EPRI at (704) 502-6440.

Sincerely,

Attachment(s)
c: Sheldon Stuchell, NRC (sheldon.stuchell@nrc.gov)

1300 West W.T. Harris Boulevard, Charlotte, NC 28262-8550 USA • 704.595.2732 • Mobile 704.490.2653 • nwilmshurst@epri.com

ELECTRIC POWER RESEARCH INSTITUTE

AFFIDAVIT

RE: Request for Withholding of the Following Proprietary Information Included In:

Entergy Operations, Inc. Grand Gulf Nuclear Station Submittal to the NRC on "Pressure and Temperature Limits Report (PTLR) Up to 54 Effective Full-Power Years" Included in GE Hitachi Nuclear Energy Report NEDC-33868P, Revision 0, June 2015

I, Neil Wilmshurst, being duly sworn, depose and state as follows:

I am the Vice President and Chief Nuclear Officer at Electric Power Research Institute, Inc. whose principal office is located at 1300 W WT Harris Blvd, Charlotte, NC. ("EPRI") and I have been specifically delegated responsibility for the above-listed report that contains EPRI Proprietary Information that is sought under this Affidavit to be withheld "Proprietary Information". I am authorized to apply to the U.S. Nuclear Regulatory Commission ("NRC") for the withholding of the Proprietary Information on behalf of EPRI.

EPRI Proprietary Information is identified in the above referenced report by double brackets. An example of such identification is as follows:

[[This sentence is an example.[E]]]

Tables containing EPRI Proprietary Information are identified with double brackets before and after the object. In each case, the superscript notation [E] refers to this affidavit as the basis for the proprietary determination.

EPRI requests that the Proprietary Information be withheld from the public on the following bases:

Withholding Based Upon Privileged And Confidential Trade Secrets Or Commercial Or Financial Information (see e.g., 10 C.F.R. § 2.390(a)(4):

a. The Proprietary Information is owned by EPRI and has been held in confidence by EPRI. All entities accepting copies of the Proprietary Information do so subject to written agreements imposing an obligation upon the recipient to maintain the confidentiality of the Proprietary Information. The Proprietary Information is disclosed only to parties who agree, in writing, to preserve the confidentiality thereof.

b. EPRI considers the Proprietary Information contained therein to constitute trade secrets of EPRI. As such, EPRI holds the Information in confidence and disclosure thereof is strictly limited to individuals and entities who have agreed, in writing, to maintain the confidentiality of the Information.

c. The information sought to be withheld is considered to be proprietary for the following reasons. EPRI made a substantial economic investment to develop the Proprietary Information and, by prohibiting public disclosure, EPRI derives an economic benefit in the form of licensing royalties and other additional fees from the confidential nature of the Proprietary Information. If the Proprietary Information were publicly available to consultants and/or other businesses providing services in the electric and/or nuclear power industry, they would be able to use the Proprietary Information for their own commercial benefit and profit and without expending the substantial economic resources required of EPRI to develop the Proprietary Information.

d. EPRI's classification of the Proprietary Information as trade secrets is justified by the Uniform Trade Secrets Act which California adopted in 1984 and a version of which has been adopted by over

forty states. The California Uniform Trade Secrets Act, California Civil Code §§3426 – 3426.11, defines a "trade secret" as follows:

> "'Trade secret' means information, including a formula, pattern, compilation, program device, method, technique, or process, that:
>
> (1) Derives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and
>
> (2) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy."

e. The Proprietary Information contained therein are not generally known or available to the public. EPRI developed the Information only after making a determination that the Proprietary Information was not available from public sources. EPRI made a substantial investment of both money and employee hours in the development of the Proprietary Information. EPRI was required to devote these resources and effort to derive the Proprietary Information. As a result of such effort and cost, both in terms of dollars spent and dedicated employee time, the Proprietary Information is highly valuable to EPRI.

f. A public disclosure of the Proprietary Information would be highly likely to cause substantial harm to EPRI's competitive position and the ability of EPRI to license the Proprietary Information both domestically and internationally. The Proprietary Information can only be acquired and/or duplicated by others using an equivalent investment of time and effort.

I have read the foregoing and the matters stated herein are true and correct to the best of my knowledge, information and belief. I make this affidavit under penalty of perjury under the laws of the United States of America and under the laws of the State of North Carolina.

Executed at 1300 W WT Harris Blvd being the premises and place of business of Electric Power Research Institute, Inc.

Date: 6-24-2015

Neil Wilmshurst

(State of North Carolina)
(County of Mecklenburg)

Subscribed and sworn to (or affirmed) before me on this 24th day of June, 2015 by Neil Wilmshurst, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Signature Deborah H. Rouse (Seal)

My Commission Expires 2nd day of April, 2016